

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 2026

OR

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

For the transition period _____ to _____

Commission File Number: 001-37362

Black Stone Minerals, L.P.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

47-1846692

(I.R.S. Employer
Identification No.)

1001 Fannin Street, Suite 2020

Houston, Texas

(Address of principal executive offices)

77002

(Zip code)

(713) 445-3200

(Registrant's telephone number, including area code)

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

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

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

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

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

Large accelerated filer

☒

Non-accelerated filer

☐

Accelerated filer

☐

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 May 1, 2026, there were 212,499,331 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. Condensed Financial Statements

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES CONSOLIDATED BALANCE SHEETS

(Unaudited)
(In thousands)

	March 31, 2026	December 31, 2025
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 11,612	\$ 1,478
Accrued revenue and accounts receivable	75,352	65,572
Commodity derivative assets, net	1,826	18,864
Prepaid expenses and other current assets	6,901	9,722
TOTAL CURRENT ASSETS	95,691	95,636
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of \$1,075,256 and \$1,063,709 at March 31, 2026 and December 31, 2025, respectively	3,091,255	3,079,340
Accumulated depreciation, depletion, amortization and impairment	(1,864,956)	(1,855,332)
Oil and natural gas properties, net	1,226,299	1,224,008
Other property and equipment, net of accumulated depreciation of \$16,051 and \$15,768 at March 31, 2026 and December 31, 2025, respectively	993	1,126
NET PROPERTY AND EQUIPMENT	1,227,292	1,225,134
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	15,433	14,784
TOTAL ASSETS	\$ 1,338,416	\$ 1,335,554
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	\$ 2,761	\$ 2,823
Accrued liabilities	7,925	19,388
Commodity derivative liabilities, net	27,624	—
Other current liabilities	2,669	2,412
TOTAL CURRENT LIABILITIES	40,979	24,623
LONG-TERM LIABILITIES		
Credit facility	187,000	154,000
Accrued incentive compensation	638	1,011
Commodity derivative liabilities, net	8,564	—
Asset retirement obligations	22,930	22,716
Other long-term liabilities	4,623	4,748
TOTAL LIABILITIES	264,734	207,098
COMMITMENTS AND CONTINGENCIES (Note 7)		
MEZZANINE EQUITY		
Partners' equity – Series B cumulative convertible preferred units, 14,711 units outstanding at March 31, 2026 and December 31, 2025, respectively	300,478	300,478
EQUITY		
Partners' equity – general partner interest	—	—
Partners' equity – common units, 212,493 and 211,873 units outstanding at March 31, 2026 and December 31, 2025, respectively	773,204	827,978
TOTAL EQUITY	773,204	827,978
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	\$ 1,338,416	\$ 1,335,554

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

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

	Three Months Ended March 31,	
	2026	2025
REVENUE		
Oil and condensate sales	\$ 54,114	\$ 50,093
Natural gas and natural gas liquids sales	63,408	58,235
Lease bonus and other income	6,387	6,925
Revenue from contracts with customers	123,909	115,253
Gain (loss) on commodity derivative instruments, net	(64,550)	(56,001)
TOTAL REVENUE	59,359	59,252
OPERATING (INCOME) EXPENSE		
Lease operating expense	1,893	2,162
Production costs and ad valorem taxes	9,200	10,185
Exploration expense	4,625	5,110
Depreciation, depletion, and amortization	9,785	9,130
General and administrative	16,832	15,172
Accretion of asset retirement obligations	389	332
TOTAL OPERATING EXPENSE	42,724	42,091
INCOME FROM OPERATIONS	16,635	17,161
OTHER INCOME (EXPENSE)		
Interest and investment income	32	64
Interest expense	(3,361)	(1,397)
Other income (expense), net	(34)	120
TOTAL OTHER EXPENSE	(3,363)	(1,213)
NET INCOME	13,272	15,948
Distributions on Series B cumulative convertible preferred units	(7,366)	(7,366)
NET INCOME ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	\$ 5,906	\$ 8,582
ALLOCATION OF NET INCOME:		
General partner interest	\$ —	\$ —
Common units	5,906	8,582
	\$ 5,906	\$ 8,582
NET INCOME ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:		
Per common unit (basic)	\$ 0.03	\$ 0.04
Per common unit (diluted)	\$ 0.03	\$ 0.04
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:		
Weighted average common units outstanding (basic)	212,369	211,253
Weighted average common units outstanding (diluted)	212,369	211,253

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
BALANCE AT DECEMBER 31, 2025	211,873	\$ 827,978
Repurchases of common units	(162)	(2,335)
Restricted units granted, net of forfeitures	782	—
Equity-based compensation	—	5,688
Distributions to common unitholders (\$0.30 per unit)	—	(63,700)
Charges to partners' equity for accrued distribution equivalent rights	—	(333)
Distributions on Series B cumulative convertible preferred units (\$0.50 per unit)	—	(7,366)
Net income	—	13,272
BALANCE AT MARCH 31, 2026	212,493	\$ 773,204

	Common units	Partners' equity
BALANCE AT DECEMBER 31, 2024	210,695	\$ 828,961
Repurchases of common units	(221)	(3,289)
Issuance of common units for acquisition of oil and natural gas properties	256	3,905
Restricted units granted, net of forfeitures	900	—
Equity-based compensation	—	5,919
Distributions to common unitholders (\$0.375 per unit)	—	(79,177)
Charges to partners' equity for accrued distribution equivalent rights	—	(414)
Distributions on Series B cumulative convertible preferred units (\$0.50 per unit)	—	(7,366)
Net income	—	15,948
BALANCE AT MARCH 31, 2025	211,630	\$ 764,487

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

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

	Three Months Ended March 31,	
	2026	2025
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	\$ 13,272	\$ 15,948
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	9,785	9,130
Accretion of asset retirement obligations	389	332
Amortization of deferred charges	262	274
(Gain) loss on commodity derivative instruments, net	64,550	56,001
Net cash (paid) received on settlement of commodity derivative instruments	(12,244)	(3,611)
Equity-based compensation	3,551	3,055
Changes in operating assets and liabilities:		
Accrued revenue and accounts receivable	(9,775)	(6,860)
Prepaid expenses and other current assets	2,821	(4,248)
Accounts payable, accrued liabilities, and other	(9,949)	(5,145)
Settlement of asset retirement obligations	(102)	(41)
NET CASH PROVIDED BY OPERATING ACTIVITIES	62,560	64,835
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions of oil and natural gas properties	(11,549)	(10,259)
Additions to oil and natural gas properties	(175)	(129)
Additions to oil and natural gas properties leasehold costs	(236)	(3,036)
Purchases of other property and equipment	(150)	(43)
Proceeds from the sale of oil and natural gas properties	121	400
NET CASH USED IN INVESTING ACTIVITIES	(11,989)	(13,067)
CASH FLOWS FROM FINANCING ACTIVITIES		
Distributions to common unitholders	(63,700)	(79,177)
Distributions to Series B cumulative convertible preferred unitholders	(7,366)	(7,366)
Repurchases of common units	(2,335)	(3,289)
Borrowings under credit facility	82,000	81,000
Repayments under credit facility	(49,000)	(43,000)
Debt issuance costs and other	(36)	(31)
NET CASH USED IN FINANCING ACTIVITIES	(40,437)	(51,863)
NET CHANGE IN CASH AND CASH EQUIVALENTS	10,134	(95)
Cash and cash equivalents – beginning of the period	1,478	2,519
Cash and cash equivalents – end of the period	<u>\$ 11,612</u>	<u>\$ 2,424</u>
SUPPLEMENTAL DISCLOSURE		
Interest paid	\$ 3,052	\$ 1,041
Common units issued for property acquisitions	\$ —	\$ 3,905

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

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

NOTE 1 - BUSINESS AND BASIS OF PRESENTATION

Description of the Business

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

Basis of Presentation

The accompanying unaudited interim condensed 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, 2025 ("2025 Annual Report on Form 10-K").

The unaudited interim consolidated financial statements include the consolidated results of the Partnership. The results of operations for the three months ended March 31, 2026 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 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 reportable segment, which consists of a single operating segment. The Partnership generates revenue from the sale of oil and natural gas, as well as lease bonus and other income that is derived from its oil and natural gas properties. These properties are all located within the continental U.S., including all of the major onshore producing basins. Operating segments are defined as components of an enterprise for which separate financial information is evaluated regularly by the chief operating decision maker ("CODM") in deciding how to allocate resources and assess performance. The Partnership's co-chief executive officers, collectively, have been determined to be the CODM and allocate resources and assess performance based upon net income reported on the consolidated statements of operations. The significant segment expenses regularly provided to the CODM include lease operating expense, production costs and ad valorem taxes, exploration expense, depreciation, depletion, and amortization, general and administrative expense, and interest expense. Other segment items include accretion of asset retirement obligations, gain on sale of assets, net, interest and investment income, and other income (expense), net. These significant expenses and other segment items are the same as the line items presented in the consolidated statements of operations. The CODM is not regularly provided with additional expense information beyond what is presented in the consolidated statements of operations. The measure of segment assets is reported on the consolidated balance sheets as total assets. The CODM uses net income to evaluate the income generated from segment assets in deciding whether to reinvest profits into the Partnership's oil and natural gas properties or for other activities such as distributions to unitholders and reducing outstanding borrowings as applicable.

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

Significant accounting policies are disclosed in the Partnership's 2025 Annual Report on Form 10-K. There have been no changes in such policies or the application of such policies during the three months ended March 31, 2026.

Accrued Revenue and Accounts Receivable

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

	March 31, 2026	December 31, 2025
	(in thousands)	
Accrued revenue	\$ 71,598	\$ 62,679
Accounts receivable	3,754	2,893
Total accrued revenue and accounts receivable	<u>\$ 75,352</u>	<u>\$ 65,572</u>

Accrued Liabilities

Accrued liabilities consisted of the following:

	March 31, 2026	December 31, 2025
	(in thousands)	
Accrued incentive compensation	\$ 2,747	\$ 7,824
Accrued general and administrative	1,084	847
Accrued property taxes	1,751	6,029
Accrued lease operating expenses	1,053	1,985
Accrued seismic costs	—	1,500
Accrued other	1,290	1,203
Total accrued liabilities	<u>\$ 7,925</u>	<u>\$ 19,388</u>

Recent Accounting Pronouncements

In November 2024, the FASB issued ASU 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures, which enhances the disclosures required for certain expense captions in the Partnership's annual and interim consolidated financial statements. The guidance is effective for fiscal years beginning after December 15, 2026 and for interim periods beginning after December 15, 2027, with early adoption permitted. The Partnership is currently evaluating the impact of this standard on its disclosures.

NOTE 3 - OIL AND NATURAL GAS PROPERTIES

Acquisitions

During the three months ended March 31, 2026, the Partnership acquired mineral and royalty interests that consisted of primarily unproved oil and natural gas properties in East Texas from various sellers for cash consideration of \$11.5 million, including capitalized direct transaction costs, and were considered asset acquisitions. The consideration paid was funded with borrowings under the Credit Facility and funds from operating activities.

During the year ended December 31, 2025, the Partnership acquired mineral and royalty interests that consisted of primarily unproved oil and natural gas properties in East Texas from various sellers for an aggregate of \$114.5 million, including capitalized direct transaction costs, and were considered asset acquisitions. The consideration paid consisted of \$107.1 million in cash that was funded with borrowings under the Credit Facility and funds from operating activities, and \$7.4 million in equity, that was funded through the issuance of common units of the Partnership based on the fair value of the common units issued on the acquisition dates.

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

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. 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 enters into oil and natural gas derivative contracts that contain netting arrangements with each counterparty. The Partnership does not enter into derivative instruments for speculative purposes.

As of March 31, 2026, the Partnership's open derivative contracts consisted of fixed-price swap contracts. 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 statements of operations in the period of the change. All derivative gains and losses from the Partnership's derivative contracts have been recognized in revenue in the Partnership's accompanying consolidated statements of operations. Derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Partnership's accompanying consolidated balance sheets as of March 31, 2026 and December 31, 2025. See "Note 5 - Fair Value Measurements" for additional information.

The Partnership's derivative contracts expose it to credit risk in the event of nonperformance by counterparties that may adversely impact the fair value of the Partnership's commodity derivative assets. While the Partnership does not require its derivative contract counterparties to post collateral, the Partnership does evaluate the credit standing of such counterparties as deemed appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of March 31, 2026, the Partnership had eight counterparties, all of which are lenders under the Credit Facility.

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

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

		March 31, 2026		
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, net	\$ 13,818	\$ (11,992)	\$ 1,826
Long-term asset	Deferred charges and other long-term assets	6,616	(1,567)	5,049
Total assets		<u>\$ 20,434</u>	<u>\$ (13,559)</u>	<u>\$ 6,875</u>
Liabilities:				
Current liability	Commodity derivative liabilities, net	\$ 39,616	\$ (11,992)	\$ 27,624
Long-term liability	Commodity derivative liabilities, net	10,131	(1,567)	8,564
Total liabilities		<u>\$ 49,747</u>	<u>\$ (13,559)</u>	<u>\$ 36,188</u>

Classification	Balance Sheet Location	December 31, 2025		
		Gross Fair Value	Effect of Counterparty Netting	Net Carrying Value on Balance Sheet
(in thousands)				
Assets:				
Current asset	Commodity derivative assets, net	\$ 24,930	\$ (6,066)	\$ 18,864
Long-term asset	Deferred charges and other long-term assets	4,325	(196)	4,129
Total assets		<u>\$ 29,255</u>	<u>\$ (6,262)</u>	<u>\$ 22,993</u>
Liabilities:				
Current liability	Commodity derivative liabilities, net	\$ 6,066	\$ (6,066)	\$ —
Long-term liability	Commodity derivative liabilities, net	196	(196)	—
Total liabilities		<u>\$ 6,262</u>	<u>\$ (6,262)</u>	<u>\$ —</u>

Changes in the fair values of the Partnership's derivative instruments (both assets and liabilities), as well as net cash paid or received on settlements, are presented on a net basis in the accompanying consolidated statements of operations within Gain (loss) on commodity derivative instruments, net and consist of the following for the periods presented:

Derivatives not designated as hedging instruments	Three Months Ended March 31,	
	2026	2025
(in thousands)		
Beginning fair value of commodity derivative instruments	\$ 22,993	\$ (13,609)
Gain (loss) on oil derivative instruments	(65,236)	(814)
Gain (loss) on natural gas derivative instruments	686	(55,187)
Net cash paid (received) on settlements of oil derivative instruments	(3,291)	383
Net cash paid (received) on settlements of natural gas derivative instruments	15,535	3,228
Net change in fair value of commodity derivative instruments	(52,306)	(52,390)
Ending fair value of commodity derivative instruments	<u>\$ (29,313)</u>	<u>\$ (65,999)</u>

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

The Partnership had the following open derivative contracts for oil as of March 31, 2026:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Range (Per Bbl)	
			Low	High
Oil Swap Contracts:				
2026				
First Quarter	205,000	\$ 64.39	\$ 62.00	\$ 67.35
Second Quarter	615,000	64.39	62.00	67.35
Third Quarter	615,000	64.39	62.00	67.35
Fourth Quarter	615,000	64.39	62.00	67.35
2027				
First Quarter	390,000	\$ 61.07	\$ 58.13	\$ 72.05
Second Quarter	390,000	61.07	58.13	72.05
Third Quarter	390,000	61.07	58.13	72.05
Fourth Quarter	390,000	61.07	58.13	72.05

The Partnership entered into the following derivative contracts for oil subsequent to March 31, 2026:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Range (Per Bbl)	
			Low	High
Oil Swap Contracts:				
2027				
First Quarter	30,000	\$ 72.24	\$ 72.24	\$ 72.24
Second Quarter	30,000	72.24	72.24	72.24
Third Quarter	30,000	72.24	72.24	72.24
Fourth Quarter	30,000	72.24	72.24	72.24

The Partnership had the following open derivative contracts for natural gas as of March 31, 2026:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (Per MMBtu)	Range (Per MMBtu)	
			Low	High
Natural Gas Swap Contracts:				
2026				
Second Quarter	12,740,000	\$ 3.73	\$ 3.50	\$ 4.46
Third Quarter	12,880,000	3.73	3.50	4.46
Fourth Quarter	12,880,000	3.73	3.50	4.46
2027				
First Quarter	7,200,000	\$ 3.91	\$ 3.77	\$ 4.00
Second Quarter	7,280,000	3.91	3.77	4.00
Third Quarter	7,360,000	3.91	3.77	4.00
Fourth Quarter	7,360,000	3.91	3.77	4.00

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

NOTE 5 - FAIR VALUE MEASUREMENTS

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

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

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

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

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. There were no transfers into, or out of, the three levels of fair value hierarchy for the three months ended March 31, 2026 and 2025.

The carrying value of the Partnership's cash and cash equivalents, receivables, and payables approximate fair value due to the short-term nature of the instruments. The estimated carrying value of all debt as of March 31, 2026 and December 31, 2025 approximated the fair value due to variable market rates of interest.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

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

	Fair Value Measurements Using			Effect of Counterparty		
	Level 1	Level 2	Level 3	Netting	Total	
	(in thousands)					
As of March 31, 2026						
Financial Assets						
Commodity derivative instruments	\$ —	\$ 20,434	\$ —	\$ (13,559)	\$	6,875
Financial Liabilities						
Commodity derivative instruments	\$ —	\$ 49,747	\$ —	\$ (13,559)	\$	36,188
As of December 31, 2025						
Financial Assets						
Commodity derivative instruments	\$ —	\$ 29,255	\$ —	\$ (6,262)	\$	22,993
Financial Liabilities						
Commodity derivative instruments	\$ —	\$ 6,262	\$ —	\$ (6,262)	\$	—

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 when impaired.

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 had no business combinations for the three months ended March 31, 2026 or the year ended December 31, 2025. See "Note 3 - Oil and Natural Gas Properties." 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 impaired. 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. This evaluation is performed on a depletable unit basis.

When assessing producing properties for impairment, the Partnership compares the undiscounted projected future cash flows expected in connection with a depletable unit to its unamortized carrying amount to determine recoverability. When the carrying amount of a depletable unit exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties. The factors used to determine future cash flows associated with those properties include estimates of proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, and, with respect to estimating fair value, a risk-adjusted discount rate. When assessing unproved properties for impairment, an impairment loss is recognized to the extent the carrying value within a depletable unit exceeds the estimated recoverable value. The carrying value of unproved properties, including unleased mineral rights, is determined based on management's assessment of fair value using factors similar to those previously noted for proved properties, as well as geographic and geologic data.

The Partnership's estimates of fair value are determined at discrete points in time based on relevant market data. These estimates involve uncertainty, and cannot be determined with precision. There were no significant changes in valuation techniques or related inputs for the three months ended March 31, 2026 or the year ended December 31, 2025. There were no assets measured at fair value on a non-recurring basis for the three months ended March 31, 2026 or the year ended December 31, 2025.

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

NOTE 6 - CREDIT FACILITY

The Partnership maintains a senior secured revolving credit agreement, as amended (the "Credit Facility"). The Credit Facility has an aggregate maximum credit amount of \$1.0 billion and terminates on October 31, 2030. The commitment of the lenders equals the least of the aggregate maximum credit amount, the then-effective borrowing base, and the aggregate elected commitment, as it may be adjusted from time to time. The amount of the borrowing base is redetermined semi-annually, usually in October and April, and is derived from the value of the Partnership's oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. The Partnership and the lenders (at the direction of two-thirds of the lenders) each have discretion to request a borrowing base redetermination one time between scheduled redeterminations. The Partnership also has the right to request a redetermination following the acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition. The borrowing base is also adjusted if the Partnership terminates its hedge positions or sells 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. The borrowing base was reaffirmed in April 2025, October 2025 and April 2026 at \$580.0 million. After each redetermination, the Partnership elected to maintain cash commitments under the Credit Facility at \$375.0 million. The next semi-annual redetermination is scheduled for October 2026.

The Partnership's borrowings under the Credit Facility bear interest at a floating rate determined by the type of loan the Partnership has elected to take: a SOFR loan or a base-rate loan. Both types of loans bear interest at a reference rate plus a margin that varies with the amount of borrowings outstanding under the Credit Facility. The reference rate for SOFR loans is equal to SOFR as published by the Federal Reserve Bank of New York, adjusted for the borrowing term, plus 2.50%, which is referred to as Adjusted Term SOFR. Effective October 31, 2025, Adjusted Term SOFR was amended to remove the additional 0.10% "adjustment" to the underlying SOFR reference rate. The reference rate for base rate loans is the highest of (a) Wells Fargo's prime commercial lending rate for that day, (b) the Federal Funds Rate in effect on that day plus 0.50%, and (c) Adjusted Term SOFR for a one-month tenor, plus 1.00%. As of March 31, 2026 and December 31, 2025, the applicable margin for the base rate loans ranged from 1.50% to 2.50%, and the margin for SOFR loans ranged from 2.50% to 3.50%.

The Partnership is 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 SOFR breakage, and is required to be paid (a) if the amount outstanding exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise, in some cases subject to a cure period, or (b) at the maturity date.

The weighted-average interest rate of the Credit Facility was 6.56% during the three months ended March 31, 2026 and 7.03% during the year ended December 31, 2025. 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. The Credit Facility is secured by substantially all of the Partnership's oil and natural gas production and assets.

The Credit Facility contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Credit Facility requires the Partnership to maintain a current ratio of not less than 1.0:1.0 and a ratio of total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization, and Exploration) of not more than 3.5:1.0. Distributions are not permitted if there is a default under the Credit Facility (including the failure to satisfy one of the financial covenants), if the availability under the Credit Facility is less than 10% of the lenders' commitments, or if total debt to EBITDAX is greater than 3.0:1.0. As of March 31, 2026, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was \$187.0 million and \$154.0 million at March 31, 2026 and December 31, 2025, respectively. The unused portion of the available borrowings under the Credit Facility was \$188.0 million and \$221.0 million at March 31, 2026 and December 31, 2025, respectively.

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
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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 material to the unaudited interim consolidated financial statements, and no provision for potential remediation costs has been recorded.

Litigation

From time to time, the Partnership is involved in legal actions and claims arising in the ordinary course of business. The Partnership believes existing claims as of March 31, 2026 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 expenses in the consolidated statements of operations for the periods presented:

	Three Months Ended March 31,	
	2026	2025
	(in thousands)	
Cash—short and long-term incentive plans	\$ 1,505	\$ 1,286
Equity-based compensation—restricted common units	1,059	963
Equity-based compensation—restricted performance units	1,901	1,542
Board of Directors incentive plan	591	550
Total incentive compensation expense	<u>\$ 5,056</u>	<u>\$ 4,341</u>

For the three months ended March 31, 2026, the Partnership repurchased 162,066 common units at a weighted average price of \$14.41 per unit for the purpose of satisfying tax withholding obligations upon the vesting of certain long-term incentive equity awards held by the Partnership's executive officers and certain other employees. Specifically, when an employee's equity award vests, the Partnership withholds a portion of the units to cover the employee's tax liability.

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 \$20.39 per Series B cumulative convertible preferred unit, resulting in total proceeds of approximately \$300.0 million.

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
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The Series B cumulative convertible preferred units are entitled to quarterly distributions based on an annual distribution rate (the “Distribution Rate”), which is subject to adjustment every two years (each, a “Readjustment Date”) with the last Readjustment Date on November 28, 2025. The rate set on each Readjustment Date is equal to the greater of (i) the Distribution Rate in effect immediately prior to the relevant Readjustment Date and (ii) the 10-year Treasury Rate as of such Readjustment Date plus 5.5% per annum; provided, however, that for any quarter in which quarterly distributions are accrued but unpaid, the Distribution Rate shall be increased by 2.0% per annum for such quarter. The Distribution Rate was adjusted to 9.8% effective November 28, 2023 and remained the same at 9.8% for the November 28, 2025 Readjustment Date. The Partnership cannot pay any distributions on any junior securities, including common units, prior to paying the quarterly distribution payable to the preferred units, including any previously accrued and unpaid distributions. The Series B cumulative convertible preferred units have a stated liquidation preference of \$21.41 per unit, or \$315.0 million in the aggregate, plus any accrued and unpaid distributions, or if greater, the amount such units would be entitled to if converted into common units.

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 \$20.39, 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 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 Partnership has the option to redeem all or a portion (equal to or greater than \$100 million) of the Series B cumulative convertible preferred units during biennial 90-day windows. On August 21, 2025, the Partnership entered into an agreement with the holders of its Series B cumulative convertible preferred units. Under the agreement, the Partnership agreed not to exercise its redemption option, and the holders agreed to vote their preferred units in accordance with the recommendations of the Partnership's Board of Directors on ordinary course matters and to certain customary transfer and standstill restrictions. These provisions remain in effect through November 27, 2027, with the next redemption window opening on November 28, 2027.

The Partnership must provide 20 business days' notice to the holders of the Series B cumulative convertible preferred units of its intent to redeem, and the holders may either allow the redemption to occur or elect to convert the Series B cumulative convertible preferred units into common units as described above.

The Series B cumulative convertible preferred units had a carrying value of \$300.5 million, including accrued distributions of \$7.4 million, as of March 31, 2026 and December 31, 2025.

The Series B cumulative convertible preferred units are classified as mezzanine equity on the consolidated balance sheets since certain provisions of redemption are outside the control of the Partnership.

NOTE 10 - EARNINGS PER UNIT

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

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

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

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

	Three Months Ended March 31,	
	2026	2025
	(in thousands, except per unit amounts)	
NET INCOME	\$ 13,272	\$ 15,948
Distributions on Series B cumulative convertible preferred units	(7,366)	(7,366)
NET INCOME ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	\$ 5,906	\$ 8,582
ALLOCATION OF NET INCOME:		
General partner interest	\$ —	\$ —
Common units	5,906	8,582
	\$ 5,906	\$ 8,582
NUMERATOR:		
Numerator for basic EPU - net income attributable to common unitholders	\$ 5,906	\$ 8,582
Effect of dilutive securities	—	—
Numerator for diluted EPU - net income attributable to common unitholders after the effect of dilutive securities	\$ 5,906	\$ 8,582
DENOMINATOR:		
Denominator for basic EPU - weighted average common units outstanding (basic)	212,369	211,253
Effect of dilutive securities	—	—
Denominator for diluted EPU - weighted average number of common units outstanding after the effect of dilutive securities	212,369	211,253
NET INCOME ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:		
Per common unit (basic)	\$ 0.03	\$ 0.04
Per common unit (diluted)	\$ 0.03	\$ 0.04

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

	Three Months Ended March 31,	
	2026	2025
	(in thousands)	
Potentially dilutive securities (common units):		
Series B cumulative convertible preferred units on an as-converted basis	15,072	15,072

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
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NOTE 11 - COMMON UNITS

Common Units

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

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

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

- *first*, to the holders of the Series B cumulative convertible preferred units in an amount equal to the Distribution Rate applied to the face amount of the preferred units per annum. The Distribution Rate was adjusted to 9.8% effective November 28, 2023 and remained the same at 9.8% for the November 28, 2025 Readjustment Date.
- *second*, to the holders of common units.

Common Unit Repurchase Program

On October 30, 2023, the Board authorized a \$150.0 million unit repurchase program, terminating its existing \$75.0 million program authorized in 2018. The unit repurchase program authorizes the Partnership to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. The Partnership made no repurchases under this program for the three months ended March 31, 2026. The program is funded from the Partnership's cash on hand or through borrowings under the Credit Facility. Any repurchased units are canceled.

NOTE 12 - SUBSEQUENT EVENTS

Distribution

On April 22, 2026, the Board approved a distribution for the three months ended March 31, 2026 of \$0.30 per common unit. Distributions will be payable on May 15, 2026 to unitholders of record at the close of business on May 8, 2026.

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 condensed 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, 2025 ("2025 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 volatility of realized oil and natural gas prices;
- the level of production on our properties;
- the overall supply and demand for oil and natural gas, regional supply and demand factors, delays, or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- 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 and Haynesville 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;

- domestic and foreign trade policies, including tariffs and other controls on imports or exports of goods, including energy products and energy-related products;
- future operating results;
- future cash flows and liquidity, including our ability to generate sufficient cash to pay quarterly distributions;
- exploration and development drilling prospects, inventories, projects, and programs;
- operating hazards faced by our operators;
- the ability of our operators to keep pace with technological advancements;
- conservation measures and general concern about the environmental impact of the production and use of fossil fuels;
- cybersecurity incidents, including data security breaches or computer viruses; and
- certain factors discussed elsewhere in this filing.

For additional information regarding known material factors that could cause our actual results to differ from our projected results, please see “Risk Factors” in our 2025 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 ("U.S."). Our principal business is maximizing the value of our existing portfolio of mineral and royalty assets through active management. We maximize value through marketing our mineral assets for lease and creatively structuring the terms on those leases to encourage and accelerate drilling activity. We believe our large, diversified asset base and long-lived, non-cost-bearing mineral and royalty interests provide for stable production and reserves over time, allowing the majority of generated cash flow to be distributed to unitholders. Alongside our primary focus on traditional revenue streams from our asset base, we will continue to explore the relevance of our assets in energy transition, including opportunities in renewable energy and carbon sequestration.

As of March 31, 2026, our mineral and royalty interests were located in 41 states in the continental U.S., including all of the major onshore producing basins. These non-cost-bearing interests include ownership in approximately 71,000 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. 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

Development Activity

During the first quarter, Adamas Energy (formerly Aethon Energy, "Adamas") was operating three rigs on our Angelina and San Augustine acreage in the Shelby Trough. Adamas's development program remains on track, with 4 wells spud in the first quarter of 2026 as part of the current program year ending June 30, 2026, an additional 4 wells expected in the second quarter of 2026 to complete that program year, and 10 more wells expected in the second half of 2026 as part of the next program year. Adamas successfully turned to sales 7 gross (0.5 net) wells during the first quarter and expects to turn to sales 12 gross (1.2 net) wells during the remainder of 2026.

Our agreement with Revenant Energy ("Revenant") covers 270,000 gross acres in which we currently control approximately 122,000 undeveloped net acres. Revenant is obligated to drill a minimum of 6 wells in 2026, increasing annually to a minimum of 25 wells per year by 2030. We also secured a non-operated working interest partner for the development. In November 2025, the agreement was amended to maintain the 6-well commitment for 2026 and convert future commitments to

completed gross lateral-foot targets at one well per 7,000 lateral feet, allowing longer laterals while keeping overall development levels unchanged. Revenant spud two wells in the first quarter of 2026, one of which experienced a loss of well control incident in April 2026. We are currently assessing the potential impact of this incident on Revenant's first program year development program and related well commitments.

In November 2025, we entered into a 220,000 gross acre development agreement with Caturus Energy, LLC ("Caturus"), which aims to push the Shelby Trough westward towards the Western Haynesville. Activity will begin with approximately 2 gross (0.2 net) wells in the second half of 2026 and ramp to approximately 12 gross (0.8 net) wells annually by 2031, supported by minimum annual lateral-foot requirements, all net to our interest. In addition to the 2 gross wells in 2026, Caturus plans to drill a pilot well stepping out towards Houston County, consistent with the terms of the agreement.

In the Permian Basin, Coterra Energy continues to develop our acreage in Culberson County, Texas. During the first quarter, 17 gross wells (0.6 net) were turned to sales. A separate development by another Permian operator of 25 gross (1.9 net) wells in the southern Delaware Basin is expected to come online in the second half of 2026 and first half of 2027.

For additional information about our Shelby Trough development agreements, please read "Liquidity and Capital Resources - Shelby Trough Development Agreements."

Acquisition Activity

In the first quarter of 2026, we acquired \$11.5 million of additional (primarily non-producing) mineral and royalty interests. From September 2023 through March 2026, we have completed \$251.0 million of mineral and royalty acquisitions, primarily in the expanding Shelby Trough area.

Business Environment

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

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.

Oil prices increased during the three months ended March 31, 2026 compared to the same period in 2025, primarily due to the outbreak of conflict in Iran and the closure of the Strait of Hormuz. These developments disrupted global crude oil supply chains, including reduced production levels, damage to oil infrastructure, and significant interruptions to shipping activity. Natural gas prices decreased during the three months ended March 31, 2026 relative to the prior-year period. Natural gas prices were elevated in January and early February 2026 due to colder-than-normal weather but declined over the remainder of the quarter as milder winter conditions across most of the U.S. persisted. Continued growth in natural gas production also contributed to downward pressure on prices during the quarter.

Given the dynamic nature of commodity markets, we cannot reasonably estimate how long price levels or market conditions will persist. While we use derivative instruments to partially mitigate the impact of commodity price volatility, our revenues and operating results depend significantly upon the prevailing prices for oil and natural gas.

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

Benchmark Prices¹	2026		2025	
	First Quarter		First Quarter	
WTI spot oil (\$/Bbl)	\$	102.86	\$	71.87
Henry Hub spot natural gas (\$/MMBtu)		2.88		4.11

¹ Source: EIA

Rig Count

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

The following table shows the rig count at the end of each quarter presented:

U.S. Rotary Rig Count ¹	2026	2025
	First Quarter	First Quarter
Oil	409	484
Natural gas	127	103
Other	7	5
Total	543	592

¹ Source: Baker Hughes Incorporated

Natural Gas Storage

The majority of the production volumes attributable to our interests is derived from natural gas production. 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 U.S. Energy Information Administration ("EIA") expects inventories will rise to 4.0 Tcf at the end of October 2026, which would be 6% higher than the five-year average.

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

Region ¹	2026	2025
	First Quarter	First Quarter
East	270	284
Midwest	350	364
Mountain	208	165
Pacific	258	202
South Central	775	758
Total	1,861	1,773

¹ Source: EIA

Natural Gas Exports

Net natural gas exports averaged 17.5 Bcf per day during the first quarter of 2026, a 16% increase from the 2025 average. The EIA forecasts average exports of 16.8 Bcf per day for the remainder of 2026 and 18.6 Bcf per day for 2027. The EIA forecast reflects assumptions that U.S. liquefied natural gas ("LNG") exports will increase as new LNG export projects begin operations in 2026. While geopolitical developments, including the conflict in Iran, have increased global energy market volatility, their near-term impact on U.S. natural gas prices has been limited given constrained LNG export capacity.

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

- *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. Although the growth in LNG export capacity and global shipping has increased connectivity among certain markets, transportation remains infrastructure-dependent and subject to capacity constraints, and prices may continue to vary by region.

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. Under a fixed-price swap contract, a counterparty is required to make a payment to us if the settlement price is less than the contract strike price, and we are required to make a payment to the counterparty if the settlement price is greater than the contract strike price. Under a costless collar contract, we receive a payment from the counterparty if the settlement price is below the floor price, and we make a payment to the counterparty if the settlement price is above the ceiling price. If we have multiple contracts outstanding with a single counterparty, unless restricted by our agreement, we will net settle the contract payments. 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. We may employ contractual arrangements other than fixed-price swap contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue. Our open oil and natural gas derivative contracts as of March 31, 2026 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, but not required, to hedge, using swaps and collars with a term of no more than four years, up to 90% of our expected future volumes for the first 24 months, 70% for months 25 through 36, and 50% for months 37 through 48. As of March 31, 2026, we had hedged a portion of our expected future volumes for the remainder of 2026 and 2027.

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. 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, if any, accretion of asset retirement obligations, seismic data acquisition costs, non-cash equity-based compensation, unrealized gains and losses on commodity derivative instruments, and gains and losses on sales of assets, if any. We define Distributable Cash Flow as Adjusted EBITDA plus or minus amounts for certain non-cash operating activities, cash interest expense, distributions to preferred unitholders, and restructuring charges, if any.

Beginning with the year ended December 31, 2025, we revised our definition of Adjusted EBITDA to exclude seismic data acquisition costs, which are included in Exploration expense on our consolidated statements of operations. Comparative amounts for the three months ended March 31, 2025 for each of Adjusted EBITDA and Distributable Cash Flow have been recast to conform to the current period presentation. Management believes this revised definition enhances comparability between periods and reflects the Partnership's view of seismic data acquisition costs as investments that support the long-term development and value of its mineral and royalty interests.

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 or liquidity presented in accordance with generally accepted accounting principles ("GAAP") in the U.S. 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) to Adjusted EBITDA and Distributable Cash Flow for the periods indicated:

	Three Months Ended March 31,	
	2026	2025
	(in thousands)	
Net income	\$ 13,272	\$ 15,948
Adjustments to reconcile to Adjusted EBITDA:		
Depreciation, depletion, and amortization	9,785	9,130
Interest expense	3,361	1,397
Income tax expense (benefit)	62	(85)
Accretion of asset retirement obligations	389	332
Seismic data acquisition costs	4,256	4,829
Equity-based compensation	3,551	3,055
Unrealized (gain) loss on commodity derivative instruments	52,306	52,390
Adjusted EBITDA	86,982	86,996
Adjustments to reconcile to Distributable Cash Flow:		
Change in deferred revenue	(1)	(1)
Cash interest expense	(3,099)	(1,123)
Preferred unit distributions	(7,366)	(7,366)
Distributable Cash Flow	\$ 76,516	\$ 78,506

Results of Operations

Three Months Ended March 31, 2026 Compared to Three Months Ended March 31, 2025

The following table shows our production, revenue, and operating expenses for the periods presented:

	Three Months Ended March 31,				
	2026	2025	Variance		
	(Dollars in thousands, except for realized prices)				
Production:					
Oil and condensate (MBbls)	785	716	69	9.6 %	
Natural gas (MMcf) ¹	15,266	14,853	413	2.8 %	
Equivalents (MBoe)	3,329	3,192	137	4.3 %	
Equivalents/day (MBoe)	37.0	35.5	1.5	4.2 %	
Realized prices, without derivatives:					
Oil and condensate (\$/Bbl)	\$ 68.94	\$ 69.96	\$ (1.02)	(1.5)%	
Natural gas (\$/Mcf) ¹	4.15	3.92	0.23	5.9 %	
Equivalents (\$/Boe)	\$ 35.30	\$ 33.94	\$ 1.36	4.0 %	
Revenue:					
Oil and condensate sales	\$ 54,114	\$ 50,093	\$ 4,021	8.0 %	
Natural gas and natural gas liquids sales ¹	63,408	58,235	5,173	8.9 %	
Lease bonus and other income	6,387	6,925	(538)	(7.8)%	
Revenue from contracts with customers	123,909	115,253	8,656	7.5 %	
Gain (loss) on commodity derivative instruments, net	(64,550)	(56,001)	(8,549)	15.3 %	
Total revenue	\$ 59,359	\$ 59,252	\$ 107	0.2 %	
Operating expenses:					
Lease operating expense	\$ 1,893	\$ 2,162	\$ (269)	(12.4)%	
Production costs and ad valorem taxes	9,200	10,185	(985)	(9.7)%	
Exploration expense	4,625	5,110	(485)	(9.5)%	
Depreciation, depletion, and amortization	9,785	9,130	655	7.2 %	
General and administrative	16,832	15,172	1,660	10.9 %	
Other expense:					
Interest expense	3,361	1,397	1,964	140.6 %	

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.

Revenue

Total revenue for the quarter ended March 31, 2026 increased compared to the quarter ended March 31, 2025. The increase in total revenue in the first quarter of 2026 is primarily due to higher oil and condensate sales and higher natural gas and NGL sales, which were partially offset by increased losses on our commodity derivative instruments and lower lease bonus and other income compared to the corresponding prior period.

Oil and condensate sales. Oil and condensate sales increased for the quarter ended March 31, 2026 as compared to the corresponding period in 2025 primarily due to increased production volumes, which were partially offset by slightly decreased realized commodity prices. The increase in oil and condensate production was driven by higher mineral and royalty volumes in the Permian Basin and the Eagle Ford trends. Our mineral and royalty interest oil and condensate volumes accounted for 96% of total oil and condensate volumes for each of the quarters ended March 31, 2026 and 2025.

Natural gas and natural gas liquids sales. Natural gas and NGL sales increased for the quarter ended March 31, 2026 as compared to the corresponding prior period. The increase was due to higher realized commodity prices between the comparative periods and increased production volumes. The increase in production was driven by higher royalty interest volumes, primarily within the Haynesville/Bossier trend. Mineral and royalty interest production accounted for 97% of our natural gas volumes for each of the quarters ended March 31, 2026 and 2025.

Gain (loss) on commodity derivative instruments. 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. During the first quarter of 2026, losses from our commodity derivative instruments increased compared to the same period in 2025. For the three months ended March 31, 2026, we recognized \$12.2 million of realized losses and \$52.3 million of unrealized losses from our oil and natural gas commodity contracts, compared to \$3.6 million of realized losses and \$52.4 million of unrealized losses in the same period in 2025. The unrealized losses on our commodity contracts during the first quarter of 2026 were primarily driven by changes in the forward commodity price curves for oil. The unrealized losses for the same period in 2025 were primarily driven by changes in the forward commodity price curves 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 first quarter of 2026 was lower than the same period in 2025. Leasing activity in the Permian Basin and proceeds from surface use waivers on our mineral acreage supporting solar development comprised the majority of lease bonus and other income for both the first quarter of 2026 and the first quarter of 2025. The surface use waivers covered mineral acreage in Mississippi for the first quarter of 2026 and Louisiana for the first quarter of 2025.

Operating Expenses

Lease operating expense. Lease operating expense includes recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased for the quarter ended March 31, 2026 as compared to the same period in 2025, primarily due to lower nonrecurring service-related expenses, including workovers.

Production costs and ad valorem taxes. Production taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the regulations of the states where the production originates, these taxes may be based on a percentage of the realized value or a fixed amount per production unit. This category also includes the costs to process and transport our production to applicable sales points. Ad valorem taxes are jurisdictional taxes levied on the value of oil and natural gas minerals and reserves. Rates, methods of calculating property values, and timing of payments vary between taxing authorities. For the quarter ended March 31, 2026, production costs and ad valorem taxes decreased compared to the quarter ended March 31, 2025. The decrease was primarily due to \$2.3 million in refunds of production costs from operators associated with deduction-free lease terms, reflecting settlements of prior period deductions, as well as lower ad valorem tax estimates. The overall decrease was partially offset by higher production taxes due to increased production revenues and volumes.

Exploration expense. Exploration expense typically consists of dry-hole expenses, payments for delay rentals where the Partnership is the lessee, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. For the quarter ended March 31, 2026, exploration expenses decreased compared to the same period in 2025, primarily due to a decrease in seismic costs.

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 increased for the quarter ended March 31, 2026 as compared to the same period in 2025 due to higher production volumes.

General and administrative. General and administrative expenses are costs not directly associated with the production of oil and natural gas and include expenses such as the cost of employee salaries and related benefits, office expenses, and fees for professional services. For the quarter ended March 31, 2026, general and administrative expenses increased as compared to the same period in 2025, primarily due to higher personnel costs, including \$1.1 million of cash compensation and \$0.5 million of equity-based compensation, driven by increased headcount. The increase in equity-based compensation was also driven by higher costs for performance-based awards due to mark-to-market adjustments reflecting changes in our common unit price during 2026 compared to 2025.

Interest expense. Interest expense increased for the quarter ended March 31, 2026 as compared to the corresponding period in 2025. The increase was due to higher average outstanding borrowings under our Credit Facility.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations and borrowings under our Credit Facility. Our primary uses of cash are for distributions to our unitholders, reducing outstanding borrowings under our Credit Facility, and for investing in our business. The Series B cumulative convertible preferred units are entitled to quarterly distributions based on an annual distribution rate (the "Distribution Rate"), which is subject to adjustment every two years (each, a "Readjustment Date") with the last Readjustment Date on November 28, 2025. The rate set on each Readjustment Date is equal to the greater of (i) the Distribution Rate in effect immediately prior to the relevant Readjustment Date and (ii) the 10-year Treasury Rate as of such Readjustment Date plus 5.5% per annum; provided, however, that for any quarter in which quarterly distributions are accrued but unpaid, the Distribution Rate shall be increased by 2.0% per annum for such quarter. The Distribution Rate was adjusted to 9.8% effective November 28, 2023 and remained the same at 9.8% for the November 28, 2025 Readjustment Date. We have the option to redeem all or a portion (equal to or greater than \$100 million) of the Series B cumulative convertible preferred units for a 90 day period beginning on each Readjustment Date at a redemption price of \$20.39 per Series B cumulative convertible preferred unit, which is equal to par value. On August 21, 2025, we entered into an agreement with the holders of the Series B cumulative convertible preferred units under which we agreed not to exercise our redemption option and the holders agreed to vote in accordance with Board recommendations and comply with customary transfer and standstill restrictions through November 27, 2027, with the next redemption window opening on November 28, 2027. Depending on market conditions among other factors, we may use funds from the future issuance of common units or other equity securities or debt to redeem some or all of the preferred units. See "Note 9 - Preferred Units" to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

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

We intend to finance any future acquisitions with cash generated from operations, borrowings from our Credit Facility, and proceeds from any future issuances of equity and debt. Over the long-term, we intend to finance our working interest capital needs with 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.

On October 30, 2023, the Board authorized a \$150.0 million unit repurchase program which authorizes us to make repurchases on a discretionary basis. The program will be funded from our cash on hand or through borrowings under the Credit Facility. Any repurchased units will be cancelled. See "Note 11 – Common Units" to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information. As of March 31, 2026, we had not made any repurchases under the program.

Cash Flows

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

	Three Months Ended March 31,		
	2026	2025	Change
	(in thousands)		
Cash flows provided by operating activities	\$ 62,560	\$ 64,835	\$ (2,275)
Cash flows used in investing activities	(11,989)	(13,067)	1,078
Cash flows used in financing activities	(40,437)	(51,863)	11,426

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 three months ended March 31, 2026 as compared to the same period of 2025. The decrease was primarily due to increased interest expense in the three months ended March 31, 2026, that resulted from higher average outstanding borrowings under our Credit Facility.

Investing Activities. Net cash used in investing activities in the three months ended March 31, 2026 decreased as compared to the same period of 2025. The decrease was primarily due to reduced amounts paid for oil and natural gas properties leasehold costs in the three months ended March 31, 2026 compared to the same period of 2025. The overall decrease was partially offset by higher acquisitions of oil and natural gas properties.

Financing Activities. Net cash used in financing activities decreased for the three months ended March 31, 2026 as compared to the same period of 2025. The decrease was primarily driven by lower distributions paid to common unitholders for the three months ended March 31, 2026, compared to the same period of 2025. The overall decrease was partially offset by lower net borrowings under our Credit Facility.

Development Capital Expenditures

Expenditures for drilling, completion, and recompletion activities associated with our non-operated working interests were \$0.2 million during the three months ended March 31, 2026. We have also spent \$0.2 million to acquire leases in areas around our drilling programs during the three months ended March 31, 2026.

Acquisitions

During the three months ended March 31, 2026, we acquired mineral and royalty interests that consisted of primarily unproved oil and natural gas properties in East Texas from various sellers for cash consideration of \$11.5 million, including capitalized direct transaction costs. The consideration paid was funded from borrowings under our Credit Facility and funds from operating activities. Our commercial strategy includes the continuation of meaningful, targeted mineral and royalty acquisitions to complement our existing positions.

See "Note 3 – Oil and Natural Gas Properties" to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

Shelby Trough Development Agreements

We are party to a series of Joint Exploration Agreements ("JEAs"; each, a "JEA") with unaffiliated operators covering portions of our undeveloped leasehold and mineral acreage in the Shelby Trough area of East Texas. These agreements grant the operator exclusive rights to develop designated acreage and reduced royalty rates in exchange for meeting minimum annual drilling commitments, as defined by either a minimum number of wells or minimum aggregate lateral feet drilled. Each JEA also includes a banking provision that allows operators that exceed their annual drilling commitments to carry forward excess drilling activity, measured by wells drilled or aggregate lateral feet, to satisfy future obligations, subject to defined caps. The agreements also allow operators to temporarily suspend drilling obligations if natural gas prices fall below certain thresholds. The duration of any such suspension period is subject to limitations specified in the agreements. Wells drilled are typically required to turn to sales within 260 days of rig release. The agreements are structured to generate value from our undeveloped acreage while limiting our exposure to capital and operational costs.

For additional information about our development activities in the Shelby Trough, please read "Recent Developments."

Adamas Joint Exploration Agreements

We have two JEAs originally entered into with Aethon Energy and now operated by Adamas, covering a portion of our acreage in San Augustine County and Angelina County in East Texas. The agreements provide for a combined annual minimum drilling commitment of 16 wells across both contract areas.

Adamas expects to drill a total of 14 wells in the current program year, ending June 30, 2026, and apply 2 of its banked wells toward its commitment. As of March 31, 2026, Adamas had spud 10 wells in the current program year and had a total of 10 banked wells.

Revenant Joint Exploration Agreement

In May 2025, we entered into a JEA with Revenant covering an expanded portion of our Shelby Trough acreage, primarily located in Angelina, Nacogdoches, and San Augustine counties in Texas. The agreement grants Revenant exclusive development rights across three designated areas of interest ("AOIs") and requires minimum annual drilling commitments that escalate over a five-year period, including test wells in certain areas, to maintain development rights across the full contract area. The agreement allows for non-operated working interest participation, and in June 2025 we entered into a farmout agreement with an external capital provider covering all of our undivided 35% working interest.

In November 2025, we entered into an amendment to the JEA that maintained the original 6-well commitment for Program Year 1, while revising the structure for subsequent years. After Program Year 1, well count commitments convert to completed gross lateral-foot commitments at a ratio of one well per 7,000 lateral feet, allowing Revenant to drill longer laterals while maintaining overall commitment levels.

The table below summarizes the minimum gross lateral-foot drilling commitments under the agreement, including both AOI-specific and contract-wide commitments, following Program Year 1:

Revenant Drilling Commitments						
Program Year	Calendar Year	AOI 1	AOI 2	AOI 3	Any AOI	Total Gross Lateral Feet
2	2027	42,000	—	—	14,000	56,000
3	2028	70,000	7,000	—	—	77,000
4	2029	84,000	14,000	14,000	—	112,000
5 and thereafter	2030 and beyond	105,000	35,000	35,000	—	175,000

Caturus Joint Exploration Agreement

In November 2025, we entered into a JEA with Caturus covering an expanded portion of our Shelby Trough acreage, primarily in Angelina, Cherokee, Houston, and Nacogdoches counties in Texas. The agreement grants Caturus exclusive development rights across the contract area and requires minimum annual drilling commitments to maintain such rights. These commitments are measured in completed lateral feet on a net basis attributable to our mineral ownership interest and include pilot and test wells in the initial program years. The minimum net lateral-foot commitments escalate over a six-year period.

The table below summarizes the minimum net lateral-foot drilling commitments under the agreement:

Caturus Drilling Commitments		
Program Year	Calendar Year	Net Lateral Feet
1	2026	6,000
2	2027	12,000
3	2028	12,600
4	2029	16,800
5	2030	21,000
6 and thereafter	2031 and beyond	25,200

Credit Facility

We maintain 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 October 31, 2030. The commitment of the lenders equals the least of the aggregate maximum credit amount, the then-effective borrowing base, and the aggregate elected commitment, as it may be adjusted from time to time. The amount of the borrowing base is redetermined semi-annually, usually in April and October. We reaffirmed the borrowing base in April 2025, October 2025 and April 2026 at \$580.0 million. After each redetermination, we elected to maintain cash commitments under the Credit Facility at \$375.0 million. The next semi-annual redetermination is scheduled for October 2026.

We are subject to various affirmative, negative, and financial maintenance covenants which pose limitations on future borrowings, leases, hedging, and sales of assets. As of March 31, 2026, we were in compliance with all debt covenants.

See "Note 6 – Credit Facility" to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

Material Cash Requirements

As of March 31, 2026, there have been no material changes to our material cash requirements previously disclosed in our 2025 Annual Report on Form 10-K.

Critical Accounting Policies and Related Estimates

As of March 31, 2026, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2025 Annual Report on Form 10-K.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of oil, natural gas, and NGLs produced by our operators. Realized prices are primarily driven by the prevailing global prices for oil and prices for natural gas and NGLs in the United States. Prices for oil, natural gas, and NGLs have been 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 mitigate the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative financial 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 the difference between the fixed contract price and the market settlement price. The market settlement 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.

Based upon our open commodity derivative positions at March 31, 2026, a hypothetical \$1 per barrel increase or decrease in the NYMEX WTI strip price would result in an increase or decrease of approximately \$3.6 million in the fair value of our oil derivative contracts. Similarly, a hypothetical \$0.10 per MMBtu increase or decrease in the NYMEX Henry Hub natural gas strip price would result in an increase or decrease of approximately \$6.8 million in the fair value of our natural gas derivative

contracts. These hypothetical changes in fair value could result in a gain or loss depending on whether commodity prices increase or decrease.

Commodity prices have been historically volatile based upon the dynamics of supply and demand. To estimate the effect lower prices would have on our reserves, we applied a 10% discount to the SEC commodity pricing for the three months ended March 31, 2026. Applying this discount results in an approximate 1.2% reduction of proved reserve volumes as compared to the undiscounted March 31, 2026 SEC pricing scenario.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of March 31, 2026, we had eight counterparties, all of which were rated BBB or better by S&P Global Ratings 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. During the three months ended March 31, 2026, we had \$176.4 million weighted average outstanding borrowings under our Credit Facility, bearing interest at a weighted average interest rate of 6.56%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of \$0.4 million for the three months ended March 31, 2026, assuming that our indebtedness remained constant throughout the period. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have any interest rate hedges in place.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management of our general partner, including our general partner's principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our general partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our general partner's principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of March 31, 2026 to provide reasonable assurance.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the quarter ended March 31, 2026 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

Although we may, from time to time, be involved in various legal claims arising out of our operations in the normal course of business, we do not believe that the resolution of these matters will have a material adverse impact on our financial condition 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 2025 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 2025 Annual Report on Form 10-K. These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

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

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table sets forth our purchases of our common units during the three months ended March 31, 2026:

Period	Purchases of Common Units			
	Total Number of Common Units Purchased ¹	Average Price Paid Per Unit	Total Number of Common Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Common Units That May Yet Be Purchased Under the Plans or Programs ²
January 1 - January 31, 2026	71,559	\$ 13.37	—	\$ 150,000,000
February 1 - February 28, 2026	90,507	15.23	—	150,000,000

¹ Consists of units withheld to satisfy tax withholding obligations upon the vesting of certain long-term incentive equity awards held by our executive officers and certain other employees.

² On October 30, 2023, the Board authorized the repurchase of up to \$150.0 million in common units. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be repurchased when we might otherwise be precluded from doing so under insider trading laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion.

Item 5. Other Information

During the three months ended March 31, 2026, none of our directors or executive officers adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

Item 6. Exhibits

Exhibit Number	Description
<u>3.1</u>	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)).
<u>3.2</u>	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)).
<u>3.3</u>	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)).
<u>3.4</u>	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)).
<u>3.5</u>	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)).
<u>3.6</u>	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)).
<u>3.7</u>	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)).
<u>4.1</u>	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)).
<u>10.1</u> [^]	2026 Form of LTI Award Grant Notice and LTI Award Agreement (Leadership Performance Units) under the Black Stone Minerals, L.P. 2025 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.14 to Black Stone Minerals, L.P.'s Annual Report on Form 10-K filed on February 24, 2026 (SEC File No. 001-37362)).
<u>31.1</u> [*]	Certification of Co-Chief Executive Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
<u>31.2</u> [*]	Certification of Co-Chief Executive Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
<u>31.3</u> [*]	Certification of Chief Financial Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
<u>32.1</u> [*]	Certification of Co-Chief Executive Officers 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.

[^] Management contract or compensatory plan or arrangement.

SIGNATURES

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

BLACK STONE MINERALS, L.P.

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

Date: May 5, 2026

By: /s/ Fowler T. Carter
Fowler T. Carter
Co-Chief Executive Officer and President
(Principal Executive Officer)

Date: May 5, 2026

By: /s/ H. Taylor DeWalch
H. Taylor DeWalch
Co-Chief Executive Officer and President
(Principal Executive Officer)

Date: May 5, 2026

By: /s/ Chris R. Bonner
Chris R. Bonner
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

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

I, Fowler T. Carter, certify that:

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

Date: May 5, 2026

/s/ Fowler T. Carter

Fowler T. Carter

Co-Chief Executive Officer

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

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

I, H. Taylor DeWalch, certify that:

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

Date: May 5, 2026

/s/ H. Taylor DeWalch

H. Taylor DeWalch

Co-Chief Executive Officer

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

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

I, Chris R. Bonner, certify that:

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

Date: May 5, 2026

/s/ Chris R. Bonner

Chris R. Bonner

Chief Financial Officer

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

**Certification of
Co-Chief Executive Officers 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”), Fowler T. Carter, Co-Chief Executive Officer of the Partnership, H. Taylor DeWalch, Co-Chief Executive Officer of the Partnership, and Chris R. Bonner, Chief Financial Officer of the Partnership, each certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

Date: May 5, 2026

/s/ Fowler T. Carter

Fowler T. Carter
Co-Chief Executive Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Date: May 5, 2026

/s/ H. Taylor DeWalch

H. Taylor DeWalch
Co-Chief Executive Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Date: May 5, 2026

/s/ Chris R. Bonner

Chris R. Bonner
Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.