UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2025

OR

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

For the transition period from _______________ to _______________

Commission file number 001-37362

Black Stone Minerals, L.P.
(Exact Name of Registrant As Specified in its charter)

Delaware	**47-1846692**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**
1001 Fannin Street, Suite 2020 **Houston, Texas**	**77002**
(Address of Principal Executive Offices)	**(Zip Code)**

(713) 445-3200

(Registrant's telephone number, including area code)

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 such files). Yes ☒ No ☐

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

Large Accelerated Filer	☒	Accelerated Filer	☐
Non-Accelerated Filer	☐	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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

The aggregate market value of the common units held by non-affiliates was $2,277,701,287 on June 30, 2025, the last business day of the registrant's most recently completed second fiscal quarter, based on a closing price of $13.08 per unit as reported by the New York Stock Exchange on such date. As of February 20, 2026, 212,333,793 common units and 14,711,219 Series B cumulative convertible preferred units of the registrant were outstanding.

Documents Incorporated by Reference: Certain information called for in Items 10, 11, 12, 13, and 14 of Part III are incorporated by reference from the registrant's definitive proxy statement for the annual meeting of unitholders.

BLACK STONE MINERALS, L.P.
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GLOSSARY OF TERMS

The following includes abbreviations and meanings of certain terms commonly used in the oil and natural gas industry that may be used in this Annual Report on Form 10-K ("Annual Report").

Authorization for Expenditures (AFE). A budgeting document, usually prepared by an operator, to list estimated expenses of drilling a well to a specified depth, casing point or geological objective, and then either completing or abandoning the well. This estimate of expenses is provided to partners for approval prior to commencement of drilling or subsequent operations.

Basin. A large depression on the earth's surface in which sediments accumulate.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

Bbl/d. Bbl per day.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil. This "Btu-equivalent" conversion metric is based on an approximate energy equivalency and does not reflect the price or value relationship between oil and natural gas.

Boe/d. Boe per day.

British Thermal Unit (Btu). The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilling well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Crude oil. Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.

Delaware Act. Delaware Revised Uniform Limited Partnership Act.

Delay rental. Payment made to the lessor under a non-producing oil and natural gas lease at the end of each year to defer a drilling obligation and continue the lease for another year during its primary term.

Deterministic method. The method of estimating reserves or resources under which a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development costs. Capital costs incurred to obtain access to proved reserves and provide facilities for extracting, treating, gathering, and storing oil and natural gas.

Development well. A well drilled within the proved area of an oil and natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Dry hole or dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Economically producible. A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Exploitation. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

GLOSSARY OF TERMS

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Extension well. A well drilled to extend the limits of a known reservoir.

Farmout agreement. An agreement with a working interest owner, called the "farmor," whereby the farmor agrees to assign some or all of the working interest to another party, called the "farmee," in exchange for certain contractually agreed services with respect to such acreage or for payment for drilling operations on the acreage.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Formation. A layer of rock which has distinct characteristics that differs from other nearby rock.

Gross acres or gross wells. The total acres or wells, as the case may be, in which an interest is owned.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

Hydraulic fracturing. A process used to stimulate production of hydrocarbons. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.

Lease bonus. Usually a one-time payment made to a mineral owner as consideration for the execution of an oil and natural gas lease.

Lease operating expense. All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface and preparing the hydrocarbons for delivery off the lease, constituting part of the current operating expenses of a working interest. Such costs include labor, supplies, repairs, maintenance, allocated overhead charges, workover costs, insurance, and other expenses incidental to production, but exclude lease acquisition or drilling or completion costs.

Liquefied natural gas (LNG). Natural gas that has been cooled to a liquid state for ease and safety of non-pressured storage or transport.

Logs. Measurements that provide information on porosity, hydraulic conductivity, and fluid content of formations drilled in fluid-filled boreholes.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

MBoe. One thousand Boe.

MBoe/d. MBoe per day.

Mcf. One thousand cubic feet of natural gas.

Mineral interests. Real-property interests that grant ownership of the oil and natural gas under a tract of land and the rights to explore for, develop, and produce oil and natural gas on that land or to lease those exploration and development rights to a third party.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

Natural gas. A combination of light hydrocarbons that exists in a gaseous state at atmospheric temperature and pressure. In nature, it is found in underground accumulations, and may potentially be dissolved in oil or may also be found in its gaseous state.

Net acres or net wells. The sum of the fractional interest owned in gross acres or gross wells, respectively.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty, overriding royalty, and other non-cost-bearing interests.

NGLs. Natural gas liquids.

Nonparticipating royalty interest (NPRI). A type of non-cost-bearing royalty interest, which is carved out of the mineral interest and represents the right, which is typically perpetual, to receive a fixed, cost-free percentage of production or revenue from production, without an associated right to lease.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil and condensate.

Oil and natural gas properties. Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.

Operator. The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

Overriding royalty interest (ORRI). A fractional, undivided interest or right of participation in the oil or natural gas, or in the proceeds from the sale of the oil or gas, produced from a specified tract or tracts, which are limited in duration to the terms of an existing lease and which are not subject to any portion of the expense of development, operation, or maintenance.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Pooling. Pooling refers to an operator's consolidation of multiple adjacent leased tracts, which may be covered by multiple leases with multiple lessors, in order to maximize drilling efficiency or to comply with state mandated well spacing requirements.

Production Costs. The production or operational costs incurred while extracting and producing, storing, and transporting oil and/or natural gas. Typically, these costs include wages for workers, facilities lease costs, equipment maintenance, well repairs, logistical support, applicable taxes, and insurance.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved developed producing reserves (PDP). Proved reserves expected to be recovered from existing completion intervals in existing wells.

Proved reserves. The estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods, and government regulations.

Proved undeveloped reserves (PUD). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Reliable technology. A grouping of one or more technologies (including computation methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market, and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Resource play or play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism, and hydrocarbon type.

Royalty interest. An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any development or operating costs.

Seismic data. Seismic data is used by scientists to interpret the composition, fluid content, extent, and geometry of rocks in the subsurface. Seismic data is acquired by transmitting a signal from an energy source, such as dynamite or water, into the earth. The energy so transmitted is subsequently reflected beneath the earth's surface and a receiver is used to collect and record these reflections.

Shale. A fine grained sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers. Shale can include relatively large amounts of organic material compared with other rock types and thus has the potential to become rich hydrocarbon source rock. Its fine grain size and lack of permeability can allow shale to form a good cap rock for hydrocarbon traps.

Spacing. The distance between wells producing from the same reservoir, often established by regulatory agencies.

Standardized measure. The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions.

Tight formation. A formation with low permeability that produces oil and/or natural gas with low flow rates for long periods of time.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest (WI). An operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property, and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Workover. Operations on a producing well to restore or increase production.

WTI. West Texas Intermediate oil, which is a light, sweet crude oil, characterized by an American Petroleum Institute ("API") gravity between 39 and 41 and a sulfur content of approximately 0.4% by weight that is used as a benchmark for the other crude oils.

SUMMARY OF RISK FACTORS

The following is a brief summary of the principal factors that make an investment in Black Stone Minerals, L.P. speculative or risky. For additional information regarding known material factors that could cause our actual results to differ from our projected results, please read Part I, Item 1A. “Risk Factors.”

- We may not generate sufficient cash from operations to pay distributions on our common units;
- The volatility of oil and natural gas prices, and the potential material reduction in demand for oil and natural gas due to factors beyond our control, greatly affects our financial condition, results of operations, and cash distributions;
- Risks exist related to our unaffiliated operators on which we depend for exploration, development and production on the properties underlying our mineral and royalty interests and non-operated working interests, including their efficiency, their timely royalty payments, and their ability to obtain needed capital or financing;
- Production-related risks may affect our business, including:
    - Production decline rates and ability to replace current and future production;
    - The willingness and ability of operators to develop or produce proved undeveloped drilling locations;
    - Yield rates for project areas on our properties in various stages of development;
    - The availability of certain materials, equipment, transportation, pipelines, and refining facilities;
    - The accuracy of our reserve estimates; and
    - Risks related to drilling and completion techniques for exploratory drilling in shale plays;
- We or our operators may be unable to obtain needed capital;
- Our credit facility has substantial restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions;
- Any acquisitions of additional mineral and royalty interests present substantial risks;
- We face ongoing environmental, legal and regulatory risks, including:
    - Potential reductions in demand for oil and natural gas resulting from conservation measures, technological advances and general concern about the environment;
    - Compliance with existing and newly-adopted laws and regulations at the federal, state and local levels;
    - Risks arising out of the threat of climate change; and
    - Operating hazards and uninsured risks such as secondary liability for damage to the environment;
- We rely on a few key individuals whose absence or loss could adversely affect our business;
- Title to the properties in which we have an interest may be impaired by title defects;
- Our partnership agreement includes certain provisions which limit the rights of and pose other risks to our common unitholders, including:
    - The ability of the board of directors (the “Board”) of our general partner to modify or revoke our cash distribution policy;
    - The limitation on fiduciary duties owed by and potential liability of our general partner, its directors and executive officers to our unitholders;
    - The restriction of the voting rights of certain large unitholders;
    - Exclusive forum, venue, and jurisdiction provisions; and
    - Our ability to authorize the issuance of additional common units and other equity interests without common unitholder approval;
- Tax-related risks, including:
    - Our tax treatment depends on our status as a partnership for federal income tax purposes, and not being subject to a material amount of entity-level taxation. Our cash available for distribution to unitholders may be substantially reduced if we become subject to entity-level taxation as a result of the Internal Revenue Service (the “IRS”) treating us as a corporation or legislative, judicial, or administrative changes, and may also be reduced by any audit adjustments if imposed directly on the partnership;
    - Even if unitholders do not receive any cash distributions from us, unitholders will be required to pay taxes on their share of our taxable income. A unitholder’s share of our taxable income may be increased as a result of the IRS successfully contesting any of the federal income tax positions we take; and
    - Tax-exempt entities and non-U.S. unitholders face unique tax issues from owning our common units that may result in adverse tax consequences to them.
- Other risks to our unitholders include:
    - Actions taken by our general partner may affect the amount of cash generated from operations that is available for distribution to unitholders;
    - The market price of our common units could be adversely affected by certain events, including increases in interest rates and the sales of substantial amounts of our common units in the public or private markets; and
    - Unitholders may have liability to repay distributions pursuant to Delaware law and common units may be subject to redemption;
- Finally, our business is subject to general risk factors likely common to most publicly traded issuers.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report 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 the 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 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 Annual Report.

For additional information regarding known material factors that could cause our actual results to differ from our projected results, please read Part I, Item 1A. "Risk Factors."

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.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Black Stone Minerals, L.P. (“BSM,” the “Partnership,” “we” or “us”) is 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.

We own mineral interests in approximately 16.9 million gross acres, with an average 43.4% ownership interest in that acreage. We also own nonparticipating royalty interests in 1.8 million gross acres and overriding royalty interests in 1.6 million gross acres. These non-cost-bearing interests, which we refer to collectively as our “mineral and royalty interests,” include ownership in approximately 71,000 producing wells. Our mineral and royalty interests are located in 41 states in the continental U.S., including all of the major onshore producing basins. Many of these interests are in active resource plays, including the Haynesville/Bossier shales in East Texas/Western Louisiana, the Wolfcamp/Spraberry/Bone Springs in the Permian Basin, the Bakken/Three Forks in the Williston Basin, and the Eagle Ford shale in South Texas. The combination of the breadth of our asset base, the long-lived, non-cost-bearing nature of our mineral and royalty interests, and our active management expose us to potential additional production and reserves from new and existing plays without being required to invest additional capital.

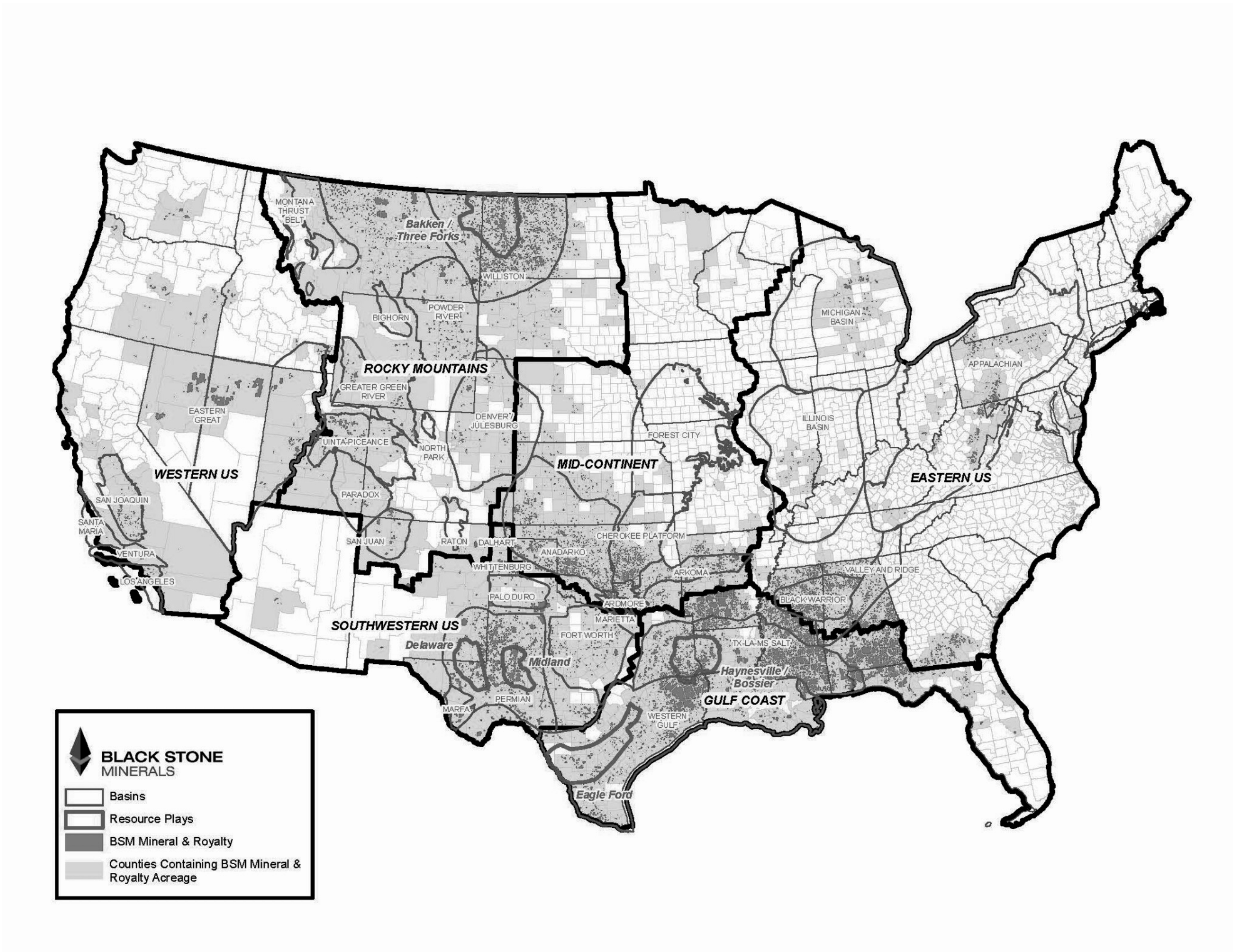
We are a publicly traded Delaware limited partnership formed on September 16, 2014. Our common units trade on the New York Stock Exchange under the symbol "BSM."

BSM files or furnishes annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to these reports with the U.S. Securities and Exchange Commission (“SEC”). Through our website, http://www.blackstoneminerals.com, we make available electronic copies of the documents we file or furnish to the SEC. Access to these electronic filings is available free of charge as soon as reasonably practicable after filing or furnishing them to the SEC.

Our Assets

As of December 31, 2025, our total estimated proved oil and natural gas reserves were 54,845 MBoe based on a reserve report prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), an independent third-party petroleum engineering firm. Of our total reserves as of December 31, 2025, approximately 88% were proved developed reserves and approximately 12% were proved undeveloped reserves. At December 31, 2025, our estimated proved reserves were 30% oil and 70% natural gas.

The locations of our oil and natural gas properties are presented on the following map. Additional information related to these properties is provided below under "*Our Properties*" by major geographical region and by material resource play, as denoted on the map below.



Mineral and Royalty Interests

Mineral interests are real-property interests that are typically perpetual and grant ownership of the oil and natural gas under a tract of land and the rights to explore for, develop, and produce oil and natural gas on that land or to lease those exploration and development rights to a third party. When those rights are leased, usually for a three-year term, we typically receive an upfront cash payment, known as lease bonus, and we retain a royalty interest, which entitles us to a cost-free percentage (usually ranging from 20% to 25%) of production or revenue from production. A lessee can extend the lease beyond the initial lease term with continuous drilling, production, or other operating activities or by making an extension payment. When drilling and production ceases, the lease terminates, allowing us to lease the exploration and development rights to another party. Mineral interests generate the substantial majority of our revenue and are also the assets over which we have the most influence.

In addition to mineral interests, we also own other types of non-cost-bearing royalty interests, which include:

- *Nonparticipating royalty interests* ("NPRIs"), which are royalty interests that are carved out of the mineral estate and represent the right, which is typically perpetual, to receive a fixed, cost-free percentage of production or revenue from production, without an associated right to lease or receive lease bonus; and

- *Overriding royalty interests* ("ORRIs"), which are royalty interests that burden working interests and represent the right to receive a fixed, cost-free percentage of production or revenue from production from a lease. ORRIs remain in effect until the associated leases expire.

We may own more than one type of mineral and royalty interest in the same tract of land. For example, where we own an ORRI in a lease on the same tract of land in which we own a mineral interest, our ORRI in that tract will relate to the same gross acres as our mineral interest in that tract. As of December 31, 2025, approximately 26% of our mineral and royalty interests are leased, calculated on a cumulative gross acreage basis for all three types of mineral and royalty interests.

The majority of our producing mineral and royalty interest acreage is pooled with third-party acreage to form pooled units. Pooling proportionately reduces our royalty interest in wells drilled in a pooled unit, and it proportionately increases the number of wells in which we have such reduced royalty interest.

Non-Operated Working Interests

We own non-operated working interests related to our mineral interests in various plays across our asset base. The majority of our working interest exposure is in the Haynesville/Bossier play in San Augustine County, Texas and Angelina County, Texas. We have farmout arrangements in place for our entire working interest position in that area. We also hold working interests acquired through working interest participation rights, which we often include in the terms of our leases. This participation right complements our core mineral and royalty interest business because it allows us to realize additional value from our minerals. Under the terms of the relevant leases, we are typically granted a unit-by-unit or a well-by-well option to participate on a non-operated working interest basis in drilling opportunities on our mineral acreage. This right to participate in a unit or well is exercisable at our sole discretion. We exercise this option when the results from prior drilling and production activities have substantially reduced the economic risk associated with development drilling and where we believe the probability of achieving attractive economic returns is high. We generally farmout or sell these participation rights to third parties and often retain some form of non-cost-bearing interest in those wells, such as an overriding royalty interest.

When we participate in non-operated working interest opportunities, we are required to pay our portion of the costs associated with drilling and operating these wells. Working interest production represented 4% of our total production volumes during the year ended December 31, 2025. As of December 31, 2025, we owned non-operated working interests in 3,173 gross (178 net) wells.

Acreage Overlap

We present tables in the following sections with information about our mineral and royalty interests and working interests. Some of these tables include acreage by interest type. We may own more than one type of interest in the same tract of land. For example, where we have acquired non-operated working interests related to our mineral interests in a given tract, our working interest acreage in that tract will relate to the same acres as our mineral interest acreage in that tract. Consequently, when acreage is presented by interest type, some of the acreage shown for one type of interest may also be included in the acreage shown for another type of interest. Because of our non-operated working interests, overlap between working interest acreage and mineral and royalty interest acreage can be significant; overlap between the different types of mineral and royalty interests is not significant.

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. 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 Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments”.

Aethon Joint Exploration Agreements

We have two JEAs with Aethon Energy ("Aethon") covering a portion of our acreage in San Augustine County and Angelina County in East Texas. In May 2025, the parties entered into a letter agreement amending the JEAs. As amended, the agreements provide for a combined annual minimum drilling commitment of 16 wells across both contract areas.

Aethon 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 December 31, 2025, Aethon had spud 6 wells in the current program year and had an inventory of 5 wells drilled in the previous program year that are expected to be turned to sales in early 2026. As of December 31, 2025, Aethon had a total of 10 banked wells.

Revenant Joint Exploration Agreement

In May 2025, we entered into a JEA with Revenant Energy (“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.

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

Revenant expects to spud more wells than its 6-well commitment for the first program year, ending December 31, 2026.

Caturus Joint Exploration Agreement

In November 2025, we entered into a JEA with Caturus Energy, LLC ("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

Farmout Agreements

We previously entered into farmout arrangements covering all our non-operated working interests under our JEAs with Aethon in San Augustine and Angelina Counties. In May 2025, the farmout agreements covering the interests under the JEAs with Aethon terminated, and Aethon assumed the associated working interests as part of an amendment to our JEAs with Aethon. In June 2025, we entered into a farmout arrangement covering all our non-operated working interests under our JEA with Revenant in Angelina, Nacogdoches, and San Augustine Counties, farming out our undivided 35% non-operated working interest to an external capital provider.

Our Properties

BSM Land Regions

We divide the contiguous U.S. into major geographical regions that we refer to as "BSM Land Regions." The following provides an overview of these regions:

- ***Gulf Coast.*** The Gulf Coast region consists of the land area along the Gulf of Mexico from South Texas through Florida. This region includes the Western Gulf (onshore), East Texas Basin, Louisiana-Mississippi Salt Basin, and South Florida Basin.

- ***Southwestern U.S.*** The Southwestern U.S. region consists of the land area north of the Mexico-United States border from Central Texas westward through Arizona. This region includes the Permian Basin, Fort Worth Basin, Bend Arch, Palo Duro Basin, Dalhart Basin, and Marfa Basin.

- ***Rocky Mountains.*** The Rocky Mountains region consists of the land area along the Rocky Mountains from Northern New Mexico through Montana and North Dakota. This region includes the Williston Basin, Montana Thrust Belt, Bighorn Basin, Powder River Basin, Greater Green River Basin, Denver-Julesburg Basin, Uinta-Piceance Basin, Park Basin, Paradox Basin, San Juan Basin, and Raton Basin.

- ***Eastern U.S.*** The Eastern U.S. region consists of the land area east of the Mississippi River and north of the Gulf Coast region. This region includes the Michigan Basin, Illinois Basin, Appalachian Basin, and Black Warrior Basin.

- ***Mid-Continent.*** The Mid-Continent region extends from Oklahoma north through Minnesota. This region includes the Anadarko Basin, Arkoma Basin, Forest City Basin, Cherokee Platform, Marietta Basin, and Ardmore Basin.

- ***Western U.S.*** The Western U.S. region consists of the land area west of the Rocky Mountains and Southwestern U.S. regions. This region includes the San Joaquin Basin, Santa Maria Basin, Ventura Basin, Los Angeles Basin, Sacramento Basin, and Eastern Great Basin.

	Acreage as of December 31, 2025							
	Mineral and Royalty Interests						Working Interests[1]	
BSM Land Region	Mineral Interests		NPRIs		ORRIs			
	Gross Acres	Net %[2]	Gross Acres	Net %[3]	Gross Acres	Net %[3]	Gross Acres	Net Acres
Gulf Coast	8,049,498	51.7 %	549,359	4.9 %	200,735	3.0 %	351,037	105,872
Southwestern U.S.	2,773,819	25.4 %	989,960	3.9 %	196,508	1.7 %	16,390	11,869
Rocky Mountains	2,123,454	15.4 %	243,295	3.4 %	802,010	2.4 %	92,919	15,844
Eastern U.S.	1,650,392	47.6 %	1,727	4.0 %	74,247	1.3 %	13,468	1,375
Mid-Continent	1,309,044	34.6 %	38,793	4.3 %	269,767	3.6 %	53,552	31,236
Western U.S.	1,025,644	89.1 %	331	1.8 %	28,029	3.3 %	—	—
Total	16,931,851	43.4 %	1,823,465	4.1 %	1,571,296	2.6 %	527,366	166,196

1 Excludes acreage for which we have incomplete seller records.

2 Refers to our average ownership interest. Ownership interest is the percentage that our undivided ownership interest in a tract bears to the entire tract. The average ownership interests shown reflect the weighted averages of our ownership interests in all tracts in the BSM Land Region. Our weighted average royalty interest for all of our mineral interests is approximately 20%, which may be multiplied by our ownership interest to approximate the average net royalty interest for our mineral interests.

3 Refers to our average royalty interest. Average royalty interest is equal to the weighted-average percentage of production or revenues (before operating costs) that we are entitled to on a tract-by-tract basis in the BSM Land Region. NPRIs may be denominated as a “fractional royalty,” which entitles the owner to the stated fraction of gross production, or a “fraction of royalty,” where the stated fraction is multiplied by the lease royalty. In cases where our land documentation does not specify the form of NPRI, we have assumed a fractional royalty for purposes of the average royalty interests shown above.

BSM Land Region	Gross Well Count as of December 31, 2025[1] MRI Wells[2]	WI Wells	Mineral and Royalty Interests: Average Daily Production (Boe/d) for the Year Ended December 31, 2025	2024	2023	Working Interests: Average Daily Production (Boe/d) for the Year Ended December 31, 2025	2024	2023
Gulf Coast	14,853	1,404	20,870	22,801	23,600	755	1,306	1,614
Southwestern U.S.	28,707	633	5,716	6,378	6,417	87	67	67
Rocky Mountains	15,954	638	4,634	4,637	4,609	353	428	519
Eastern U.S.	1,141	7	170	712	748	5	5	6
Mid-Continent	9,206	491	1,641	1,816	1,824	153	151	170
Western U.S.	601	—	225	233	238	—	—	—
Total	70,462	3,173	33,256	36,577	37,436	1,353	1,957	2,376

[1] We own both mineral and royalty interests and working interests in 1,991 of the wells shown in each column above.

[2] Refers to mineral and royalty interest wells.

Material Resource Plays

The following listing provides an overview of the resource plays we consider most material to our current and future business. These plays accounted for 73% of our aggregate production for the year ended December 31, 2025.

- ***Bakken/Three Forks.*** The Bakken shale and underlying Three Forks formation are located in the Williston Basin, which covers parts of North Dakota, South Dakota, and Montana in the U.S., and Saskatchewan and Manitoba in Canada. The U.S. portion of the Bakken/Three Forks play is within the Rocky Mountains BSM Land Region. We have significant exposure in these plays through our mineral and royalty interests as well as through our working interests.

- ***Haynesville/Bossier.*** The Haynesville/Bossier formation, located in East Texas and Western Louisiana, is within the Gulf Coast BSM Land Region and is one of the largest producing natural gas formations in the U.S. The play's prospective acreage is evenly divided between East Texas and Western Louisiana, and while we have significant exposure through our mineral and royalty interests and working interests across the entire play, the majority of our acreage is located in East Texas, with a particular concentration in the prolific southern portion of the Shelby Trough in San Augustine, Nacogdoches, and Angelina Counties.

- ***Permian-Midland***. The Midland Basin, which is a sub-basin within the Permian Basin, is located in West Texas in the Southwestern U.S. BSM Land Region. It is separated from the Delaware Basin to the west by a carbonate platform called the Central Basin Platform. We refer to the various Permian-aged resource plays within the Midland Basin as the Permian-Midland. These plays include the various members of the Spraberry and Wolfcamp formations. Our interests in the Permian-Midland resource plays are almost exclusively mineral and royalty interests.

- ***Permian-Delaware***. The Delaware Basin, which is a sub-basin within the Permian Basin, is located in West Texas and Southeastern New Mexico in the Southwestern U.S. BSM Land Region. It is separated from the Midland Basin to the east by a carbonate platform called the Central Basin Platform. We refer to the various Permian-aged resource plays within the Delaware Basin as the Permian-Delaware. These plays include the various members of the Bone Springs, Avalon, and Wolfcamp formations. Our interests in the Permian-Delaware resource plays are almost exclusively mineral and royalty interests.

- ***Eagle Ford.*** The Eagle Ford shale is located in South Texas within the Gulf Coast BSM Land Region and produces from various depths between 4,000 and 14,000 feet.

Resource Play	Acreage as of December 31, 2025							
	Mineral and Royalty Interests						Working Interests[1]	
	Mineral Interests		NPRIs		ORRIs			
	Gross Acres	Net %[2]	Gross Acres	Net %[3]	Gross Acres	Net %[3]	Gross Acres	Net Acres
Bakken/ Three Forks	397,749	17.0 %	38,623	1.4 %	12,169	1.3 %	51,749	6,650
Haynesville/ Bossier	441,603	58.9 %	30,919	4.3 %	27,392	5.3 %	174,297	47,190
Permian-Midland	221,455	4.9 %	129,047	2.3 %	102,384	0.4 %	160	4
Permian-Delaware	134,279	9.3 %	39,103	2.6 %	5,283	3.1 %	2,602	1,097
Eagle Ford	67,421	14.4 %	106,301	1.3 %	48,318	2.2 %	1,147	87

1 This excludes acreage for which we have incomplete seller records.

2 Refers to our average ownership interest. Ownership interest is the percentage that our undivided ownership interest in a tract bears to the entire tract. The average ownership interests shown reflect the weighted averages of our ownership interests in all tracts in the resource play. Our weighted average royalty interest for all of our mineral interests is approximately 20%, which may be multiplied by our ownership interest to approximate the average net royalty interest for our mineral interests.

3 Refers to our average royalty interest. Average royalty interest is equal to the weighted-average percentage of production or revenues (before operating costs) that we are entitled to on a tract-by-tract basis in the resource play. NPRIs may be denominated as a “fractional royalty,” which entitles the owner to the stated fraction of gross production, or a “fraction of royalty,” where the stated fraction is multiplied by the lease royalty. In cases where our land documentation does not specify the form of NPRI, we have assumed a fractional royalty for purposes of the average royalty interests shown above.

Resource Play	Gross Well Count as of December 31, 2025[1]		Mineral and Royalty Interests Average Daily Production (Boe/d) for the Year Ended December 31,			Working Interests Average Daily Production (Boe/d) for the Year Ended December 31,		
	MRI Wells[2]	WI Wells	2025	2024	2023	2025	2024	2023
Bakken/ Three Forks	4,610	288	3,074	3,282	3,507	276	306	361
Haynesville/ Bossier	1,588	140	15,571	18,476	18,360	569	876	1,108
Permian-Midland	4,807	5	2,886	3,846	2,991	1	1	—
Permian-Delaware	1,309	10	1,798	1,507	2,419	14	18	19
Eagle Ford	1,134	27	1,140	936	1,084	5	7	8

1 We own both mineral and royalty interests and working interests in 437 of the wells shown in each column above.

2 Refers to mineral and royalty interest wells.

Estimated Proved Reserves

Evaluation and Review of Estimated Proved Reserves

The reserves estimates as of December 31, 2025, 2024, and 2023 shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI summary reserves report incorporated herein is Mr. Connor B. Riseden. Mr. Riseden, a Licensed Professional Engineer in the State of Texas (License No. 100566), has been practicing consulting petroleum engineering at NSAI since 2006 and has over four years of prior industry experience. He graduated from Texas A&M University in 2001 with a Bachelor of Science Degree in Petroleum Engineering and from Tulane University in 2005 with a Master of Business Administration Degree. As technical principal, Mr. Riseden meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry standard practices to engineering evaluations as well as applying SEC and other industry reserves definitions and guidelines. NSAI does not own an interest in us or any of our properties, nor is it employed by us on a contingent basis. A copy of NSAI's estimated proved reserve report, dated as of January 9, 2026 and effective as of December 31, 2025, is attached as Exhibit 99.1 to this Annual Report.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our third-party reserve engineers to ensure the integrity, accuracy, and timeliness of the data used to calculate our estimated proved reserves. Our internal technical team members met with our third-party reserve engineers periodically during the period covered by the above referenced reserve report to discuss the assumptions and methods used in the reserve estimation process. We provided historical information to the third-party reserve engineers for our properties, such as oil and natural gas production, well test data, realized commodity prices, and operating and development costs. We also provided ownership interest information with respect to our properties. Stephanie Parish, our Manager, Reserves, was primarily responsible for overseeing the preparation of our reserve estimates for 2025 and 2024. Ms. Parish is a petroleum engineer with approximately 27 years of reservoir-engineering experience. Garrett Gremillion, our former Vice President, Engineering, was primarily responsible for overseeing the preparation of our reserve estimates for 2023. Mr. Gremillion is a petroleum engineer and had approximately 14 years of reservoir-engineering experience as of December 31, 2023.

Our historical proved reserve estimates were prepared in accordance with our internal control procedures. Throughout the year, our technical team met with NSAI to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data used in the reserves evaluation software as well as reviews by our internal engineering staff and management, which include the following:

- Comparison of historical operating expenses from the lease operating statements to the operating costs input in the reserves database;
- Review of working interests, net revenue interests, and royalty interests in the reserves database against our well ownership system;
- Review of historical realized commodity prices and differentials from index prices compared to the differentials used in the reserves database;
- Evaluation of capital cost assumptions derived from Authority for Expenditure estimates received;
- Review of actual historical production volumes compared to projections in the reserve report;
- Discussion of material reserve variances among our internal reservoir engineers; and
- Review of preliminary reserve estimates by our senior management with our internal technical staff.

Estimation of Proved Reserves

In accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" means deterministically, the quantities of oil and/or natural gas are much more likely to be achieved than not, and probabilistically, there should be at least a 90% probability of recovering volumes equal to or exceeding the estimate. All our estimated proved reserves as of December 31, 2025, 2024, and 2023 are based on deterministic methods. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by using reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated net proved reserves, NSAI used technical data including, but not limited to, well test data and production data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity.

Summary of Estimated Proved Reserves

Estimates of reserves are prepared using oil and natural gas prices equal to the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month within the year the estimates are prepared. For estimates of oil reserves, the average WTI spot oil prices used were $66.01, $76.32, and $78.21 per barrel as of December 31, 2025, 2024, and 2023, respectively. These average prices are adjusted for quality, transportation fees, and market differentials. For estimates of natural gas reserves, the average Henry Hub prices used were $3.39, $2.13, and $2.64 per MMBtu as of December 31, 2025, 2024, and 2023, respectively. These average prices are adjusted for energy content, transportation fees, and market differentials. Natural gas prices are also adjusted to account for NGL revenue since there is not sufficient data to account for NGL volumes separately in the reserve estimates. These reserve estimates exclude NGL quantities. When taking these adjustments into account, the average adjusted prices weighted by production over the remaining lives of the properties were $63.40 per barrel for oil and $3.37 per Mcf for natural gas as of December 31, 2025, $74.14 per barrel for oil and $2.22 per Mcf for natural gas as of December 31, 2024, and $76.90 per barrel for oil and $2.63 per Mcf for natural gas as of December 31, 2023.

Reserve estimates do not include any value for probable or possible reserves that may exist. The reserve estimates represent our net revenue interest and royalty interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas may vary substantially from these estimates.

The following table presents our estimated proved oil and natural gas reserves:

	As of December 31,		
	2025	**2024**	**2023**
		(Unaudited)	
Estimated proved developed:			
Oil (MBbls)	16,241	17,466	19,091
Natural gas (MMcf)	191,632	220,901	228,061
Total (MBoe)	48,179	54,283	57,101
Estimated proved undeveloped:			
Oil (MBbls)	395	—	—
Natural gas (MMcf)	37,625	18,580	44,235
Total (MBoe)	6,666	3,097	7,373
Estimated proved reserves:			
Oil (MBbls)	16,636	17,466	19,091
Natural gas (MMcf)	229,257	239,481	272,296
Total (MBoe)	54,845	57,380	64,474
Percent proved developed	87.8%	94.6%	88.6%

Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary for the same property. In addition, the results of drilling, testing, and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices, and future production rates and costs. Please read Part I, Item 1A. “Risk Factors.”

The estimated proved reserve report as of December 31, 2025 is included as an exhibit to this Annual Report. See "Note 2 - Summary of Significant Accounting Policies" to the consolidated financial statements and our "Supplemental Oil and Natural Gas Disclosures" included elsewhere in this Annual Report for additional information.

Estimated Proved Undeveloped Reserves

As of December 31, 2025, our PUDs comprised 395 MBbls of oil and 37,625 MMcf of natural gas, or 6,666 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs during the year ended December 31, 2025 (in MBoe):

	Estimated Proved Undeveloped Reserves
	(Unaudited)
As of December 31, 2024	3,097
Acquisitions of reserves	—
Divestiture of reserves	—
Extensions and discoveries	5,064
Revisions of previous estimates	777
Transfers to estimated proved developed	(2,272)
As of December 31, 2025	6,666

New PUD reserves totaling 5,064 MBoe were added during the year ended December 31, 2025, resulting from development activities in the Haynesville/Bossier play and the Permian Basin. In 2025 we did not acquire or divest any PUD reserves.

During the year ended December 31, 2025, PUD revisions accounted for a 777 MBoe increase in reserves and 2,272 MBoe of PUD reserves were converted to proved developed reserves.

During the year ended December 31, 2025, no costs were incurred relating to the development of locations that were classified as PUDs as of December 31, 2024. The PUDs that were developed during 2025 were primarily Haynesville/Bossier PUDs in which our working interest was farmed out. Additionally, during the year ended December 31, 2025, we incurred $0.6 million drilling, completing, and recompleting other wells that were not classified as PUDs as of December 31, 2024. There are no estimated future development costs projected for the development of PUD reserves associated with our working interests as of December 31, 2025. All our PUD drilling locations as of December 31, 2025 are scheduled to be drilled within five years from the date the reserves were initially booked as proved undeveloped reserves.

We generally do not have evidence of approval of our operators' development plans. As a result, our proved undeveloped reserve estimates are limited to those relatively few locations for which we have development agreements in place or have received evidence of capital commitment. As of December 31, 2025, our PUD reserves consists of 35 wells in various stages of drilling or completions. As of December 31, 2025, approximately 12% of our total proved reserves were classified as PUDs.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

For the year ended December 31, 2025, 26% of our production and 52% of our oil and natural gas revenues were related to oil and condensate production and sales, respectively. During the same period, natural gas and NGLs were 74% of our production and 48% of our oil and natural gas revenues.

The following table sets forth information regarding production of oil and natural gas and certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2025	2024	2023
Production:			
Oil and condensate (MBbls)	3,259	3,606	3,757
Natural gas (MMcf)[1]	56,237	62,984	64,647
Total (MBoe)	12,632	14,103	14,532
Average daily production (MBoe/d)	34.6	38.5	39.8
Realized Prices without Derivatives:			
Oil and condensate (per Bbl)	$ 64.24	$ 74.61	$ 76.74
Natural gas and natural gas liquids sales (per Mcf)[1]	$ 3.41	$ 2.51	$ 3.10
Unit Cost per Boe:			
Production costs and ad valorem taxes	$ 3.09	$ 3.52	$ 3.92

[1] As a mineral and royalty interest owner, we are often provided insufficient and inconsistent data 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.

Productive Wells

Productive wells consist of producing wells, wells capable of production, and exploratory, development, or extension wells that are not dry wells.

The following table sets forth information about our mineral and royalty interest and working interest wells:

	Productive Wells as of December 31, 2025[1]		
	Mineral and Royalty Interests	Working Interests	
Well Type	Gross	Gross	Net
Oil	41,921	1,817	52
Natural Gas	28,541	1,356	126
Total	70,462	3,173	178

[1] We own both mineral and royalty interests and working interests in 1,991 gross wells.

Acreage

Mineral and Royalty Interests

The following table sets forth information relating to our acreage for our mineral and royalty interests as of December 31, 2025:

BSM Land Region	Developed Acreage[1]	Undeveloped Acreage[1]	Total Acreage[1]
Gulf Coast	464,936	8,334,656	8,799,592
Southwestern U.S.	632,947	3,327,340	3,960,287
Rocky Mountains	894,553	2,274,206	3,168,759
Eastern U.S.	86,306	1,640,060	1,726,366
Mid-Continent	527,963	1,089,641	1,617,604
Western U.S.	28,341	1,025,663	1,054,004
Total	2,635,046	17,691,566	20,326,612

[1] Includes acreage for mineral interests, NPRIs, and ORRIs.

Working Interests

The following table sets forth information relating to our acreage for our non-operated working interests as of December 31, 2025:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
BSM Land Region	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	306,028	76,849	45,009	29,023	351,037	105,872
Southwestern U.S.	16,270	11,843	120	26	16,390	11,869
Rocky Mountains	92,083	15,844	836	—	92,919	15,844
Eastern U.S.	13,468	1,375	—	—	13,468	1,375
Mid-Continent	53,552	31,236	—	—	53,552	31,236
Western U.S.	—	—	—	—	—	—
Total	481,401	137,147	45,965	29,049	527,366	166,196

Undeveloped Acreage

The following table lists our net undeveloped acres leased from third party mineral owners, the net acres expiring in the years ending December 31, 2026, 2027, and 2028, and, where applicable, the net acres expiring that are subject to extension options:

	2026 Expirations		2027 Expirations		2028 Expirations	
Net Undeveloped Acreage[1]	Net Acreage without Ext. Opt.	Net Acreage with Ext. Opt.	Net Acreage without Ext. Opt.	Net Acreage with Ext. Opt.	Net Acreage without Ext. Opt.	Net Acreage with Ext. Opt.
29,049	3,434	309	2,136	3,834	4,899	1,592

[1] There are 12,845 undeveloped acres expiring between 2029 and 2032, and where applicable, subject to extension options.

Drilling Results for Our Working Interests

The following table sets forth information with respect to the number of wells in which we own a working interest completed on our properties during the periods indicated, excluding wells subject to our farmout agreements. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, the quantities of reserves found, and the economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year Ended December 31,		
	2025	2024	2023
Gross development wells:			
Productive	—	—	1.0
Dry	—	—	—
Total	—	—	1.0
Net development wells:			
Productive	—	—	0.2
Dry	—	—	—
Total	—	—	0.2
Gross exploratory wells:			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—

As of December 31, 2025, we had no wells in the process of drilling, completing or dewatering, or shut in awaiting infrastructure.

Environmental Matters

Oil and natural gas exploration, development, and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. These laws and regulations have the potential to impact production on our properties, which could materially adversely affect our business and our prospects. Numerous federal, state, and local governmental agencies, such as the U.S. Environmental Protection Agency ("EPA"), issue regulations that carry substantial administrative, civil, and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may delay or create significant financial burdens on operators' ability to explore for, develop, and produce oil and gas from our properties. The strict, joint, and several liability nature of such laws and regulations could impose liability upon our operators, or us as working interest owners if the operator fails to perform, regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons, or other waste products into the environment. In addition, many environmental statutes contain citizen suit provisions, and environmental groups frequently use these provisions to oppose oil and natural gas exploration and development activities and related projects. The long-term trend in environmental regulation has been towards more stringent regulations, and any changes that impact our operators and result in more stringent and costly pollution control or waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our business and prospects. Below is a summary of environmental laws applicable to operations on our properties.

Waste Handling

The Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development, and production activities by imposing requirements regarding waste handling. Individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. While waste products from the exploration, development and production of oil and natural gas typically constitute "solid wastes" that are subject to less stringent non-hazardous waste requirements, RCRA could be amended or the EPA or state environmental agencies could adopt policies to require those waste products to become subject to more stringent waste handling requirements. Any changes in the laws and regulations could have a material adverse effect on our operators' capital expenditures and operating expenses, which in turn could affect production from our properties and adversely affect our business and prospects.

Remediation of Hazardous Substances

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, and analogous state laws generally impose strict, joint, and several liability, without regard to fault or legality of the original conduct, for the release of a "hazardous substance" into the environment. Parties subject to liability include the current owner or operator of a contaminated facility (which can include working interest owners), a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. These "responsible parties" may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. Oil and natural gas exploration and production activities on our properties use materials that, if released, would be subject to these laws.

Water Discharges

The Federal Water Pollution Control Act of 1972, also known as the "Clean Water Act" ("CWA"), the Safe Drinking Water Act ("SDWA"), the Oil Pollution Act ("OPA"), and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters.

Under the CWA, the discharge of pollutants into jurisdictional wetlands or other federally regulated waters of the United States ("WOTUS") is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the "Corps"). The scope of jurisdiction under the CWA remains uncertain at this time. In November 2025, the EPA and the Corps proposed a rule to further update the definition of WOTUS, guided by the U.S. Supreme Court's Sackett v. EPA decision. Accordingly, any change in the CWA's jurisdiction could result in increased costs or delays with respect to obtaining permits for certain activities for our operators. In addition, spill prevention, control, and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges.

The OPA is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint, and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil into surface waters.

The SDWA grants the EPA broad authority to take action to protect public health when an underground source of drinking water is threatened with pollution that endangers humans, which could result in orders prohibiting or limiting the operations of oil and natural gas production facilities. The EPA has asserted regulatory authority pursuant to the SDWA's Underground Injection Control ("UIC") program over hydraulic fracturing activities involving the use of diesel fuel in fracturing fluids and issued guidance covering such activities. The SDWA also regulates saltwater disposal wells under the UIC Program. Concerns related to the operation of saltwater disposal wells and induced seismicity have led some states to impose limits on the total volume of produced water such wells can dispose of, order disposal wells to cease operations, or limit the construction of new wells. These seismic events have also resulted in environmental groups and local residents filing lawsuits against operators in areas where the events occur seeking damages and injunctions limiting or prohibiting saltwater disposal well construction activities and operations. A lack of saltwater disposal wells in production areas could result in increased disposal costs for our operators if they are forced to transport produced water by truck, pipeline, or other method over long distances, or force them to curtail operations.

Noncompliance with the Clean Water Act, SDWA, or the OPA may result in substantial administrative, civil, and criminal penalties, as well as injunctive obligations, all of which could affect production from our properties and adversely affect our business and prospects.

Air Emissions

The federal Clean Air Act ("CAA") and comparable state laws and regulations regulate emissions of various air pollutants. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. To the extent these laws and regulations apply to our operators, they may increase the costs of compliance for oil and natural gas producers and impact production on our properties, and federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Moreover, obtaining or renewing permits has the potential to delay the development of oil and natural gas exploration and development projects. All of these factors could impact production on our properties and adversely affect our business and results of operations.

Climate Change

The threat of climate change continues to attract considerable attention. Numerous proposals have been made and could continue to be made at the international, national, regional, and state levels of government to monitor and limit existing emissions of greenhouse gases ("GHG") as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our operators are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level and, following the change in U.S. presidential administrations, proposals have been made to repeal or otherwise modify climate change-related requirements and the EPA's GHG "Endangerment Finding." In February 2026, the Trump administration finalized a rule repealing the Endangerment Finding. This served as the basis for the majority of the EPA's GHG regulations, including existing rules that establish construction and operating permit reviews for GHG emissions from certain large stationary sources and require the monitoring and annual reporting of GHG emissions. It is uncertain at this time what impact the repeal of the Endangerment Finding will have on such regulations.

Relatedly, the regulation of methane from oil and natural gas facilities has been subject to uncertainty in recent years. In December 2023, the EPA finalized more stringent methane rules for new, modified, and reconstructed facilities, known as New Source Performance Standard ("NSPS") OOOOb, as well as rules for existing sources for the first time ever, known as OOOOc. The rules have been subject to legal challenge. In March 2025, the EPA announced plans to reconsider OOOOb and OOOOc, in line with the Trump administration's deregulatory agenda. Most recently, in November 2025, the EPA finalized an interim rule extending the compliance deadlines for certain provisions provided in OOOOb and OOOOc. Litigation challenging the EPA's final interim rule extending such compliance deadlines for new and existing oil and natural gas sources remains pending.

Separately, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, climate "superfund" laws, reporting and tracking programs, and restriction of emissions.

Litigation risks are also increasing as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas companies in state or federal court, alleging among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customers. Recently, there have also been a number of lawsuits filed against companies alleging that such companies have made misleading or unsubstantiated claims with respect to the environmental benefits of their products or services, also known as greenwashing.

There have also recently been increasing financial risks for fossil fuel producers as certain shareholders currently invested in fossil-fuel energy companies have shown that they may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders may elect not to provide funding for fossil fuel energy companies, although this trend has waned recently, with several high-profile banks and institutional investors withdrawing from various associations that aim to limit the financing of such industries. Limitation of investments in and financing for fossil fuel energy companies could result in the restriction, delay, or cancellation of drilling programs or development or production activities.

Climate change may also result in various physical risks, such as the increased frequency and intensity of extreme weather events or changes in meteorological and hydrological patterns or other physical disruptions, that could adversely impact our operations, as well as those of our operators. Such physical risks may result in damage to operators' facilities or otherwise adversely impact their operations, such as becoming subject to water use curtailments in response to drought, or experiencing reduced demand for their heating products in response to warmer winters.

Hydraulic Fracturing

Our operators engage in hydraulic fracturing to stimulate production of hydrocarbons from tight formations, including shales. The process involves the injection of water, sand, and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions, but the EPA and other federal agencies have asserted jurisdiction over certain aspects of hydraulic fracturing, although this has lessened following the change of presidential administrations.

Several states where we own interests in oil and gas producing properties, including Colorado, North Dakota, Louisiana, Oklahoma, New Mexico, and Texas, have adopted regulations that could restrict or prohibit hydraulic fracturing in certain circumstances or require the disclosure of the composition of hydraulic-fracturing fluids. For example, Texas, Oklahoma, and New Mexico have imposed certain limits on the permitting or operation of disposal wells in areas with increased instances of induced seismic events. These existing or any new legal requirements establishing seismic permitting requirements or similar restrictions on the construction or operation of disposal wells for the injection of produced water likely will result in added costs to comply and affect our operators' rate of production, which in turn could have a material adverse effect on our results of operations and financial position.

In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. Colorado legislation, for example, includes establishment of more stringent setbacks (2,000 feet instead of 500-feet) on new oil and gas development and the elimination of routine flaring and venting of natural gas at new or existing wells across the state, and its environmental regulatory commission adopted regulations aimed at curbing methane emissions from oil and gas operations. Additionally, in March 2025, the Colorado Energy and Carbon Management Commission issued regulations requiring instate operators to phase in the use of recycled produced water for hydraulic fracturing, with minimum recycling targets starting at 2% in 2026 and increasing over time (potentially up to 35% by 2038), which may result in additional costs for water treatment infrastructure, recycling facilities, and related compliance measures. Overall, we cannot predict what additional state or local requirements may be imposed in the future on oil and gas operations in the states in which we own interests. In the event state, local, or municipal legal restrictions are adopted in areas where our operators conduct operations, our operators may incur substantial costs to comply with these requirements, which may be significant in nature, experience delays, or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from the drilling of wells.

There has been controversy regarding hydraulic fracturing with regard to increased risks of induced seismicity, the use of fracturing fluids, impacts on drinking water supplies, use of water, and the potential for impacts to surface water, groundwater, and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic-fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, those laws could make it more difficult or costly for our operators to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities on our properties could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, and also to attendant permitting delays and potential increases in costs. Legislative changes could cause operators to incur substantial compliance costs. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Occupational Safety and Health Act

The Occupational Safety and Health Act ("OSHA") and comparable state laws and regulations govern the protection of the health and safety of employees. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations, and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in operations on our properties and that this information be provided to employees, state and local government authorities, and citizens.

Endangered Species

The Endangered Species Act ("ESA") and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Some of our properties may be located in areas that are or may be designated as habitats for endangered or threatened species, and previously unprotected species may later be designated as threatened or endangered in areas where we hold interests. The listing of species in areas where we hold interests could cause our operators to incur increased costs arising from species protection measures, delay the completion of exploration and production activities, and/or result in limitations on operating activities that could have an adverse impact on our business.

Title to Properties

Prior to completing an acquisition of oil and natural gas properties, we perform title reviews on high-value tracts. Our title reviews are meant to confirm quantum of oil and natural gas properties being acquired, lease status, and royalties as well as encumbrances and other related burdens. Depending on the materiality of properties, we may obtain a title opinion if we believe additional title due diligence is necessary. As a result, title examinations have been obtained on a significant portion of our properties. After an acquisition, we review the assignments from the seller for scrivener's and other errors and execute and record corrective assignments as necessary.

In addition to our initial title work, our operators conduct a thorough title examination prior to leasing and drilling a well. Should our operators' title work uncover any title defects, either we or our operators will perform curative work with respect to such defects. Our operators generally will not commence drilling operations on a property until any material title defects on such property have been cured.

We believe that the title to our assets is satisfactory in all material respects. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions, and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens, and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects.

Major Customers (Operators)

If we were to lose a significant operator on our properties, that loss could negatively affect revenue derived from our mineral and royalty interest or working interest properties. The loss of any single lessee is mitigated by our diversified operator base. Aethon represented approximately 14% of total oil and natural gas revenues for the year ended December 31, 2025; Pioneer Natural Resources and XTO Energy, subsidiaries of ExxonMobil Corporation, collectively represented approximately 13% of total oil and natural gas revenues for the year ended December 31, 2024; and no single operator exceeded 10% of total oil and natural gas revenues for the year ended December 31, 2023.

Competition

The oil and natural gas business is highly competitive in the exploration for and acquisition of reserves, the acquisition of minerals and oil and natural gas leases, and personnel required to find and produce reserves. Many companies not only explore for and produce oil and natural gas, but also conduct midstream and refining operations and market petroleum and other products on a regional, national, or worldwide basis. Certain of our competitors may possess financial or other resources substantially larger than we possess. Our ability to acquire additional minerals and properties and to discover reserves in the future will be dependent upon our ability to identify and evaluate suitable acquisition prospects and to consummate transactions in a highly competitive environment. Oil and natural gas products compete with other sources of energy available to customers, primarily based on price. These alternate sources of energy include coal, nuclear, solar, and wind. Changes in the availability or price of oil and natural gas or other sources of energy, as well as business conditions, conservation, legislation, regulations, and the ability to convert to alternate fuels and other sources of energy may affect the demand for oil and natural gas.

Seasonal Nature of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth quarters. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions can limit drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Human Capital

Overview and Structure. We consider our workforce to be our most important asset, and we have sought to structure our hiring practices, compensation and benefits programs, and employee practices to attract and retain high-quality personnel and to provide a comfortable and collegial work environment. We continue to invest in our employees by providing training opportunities, promoting diversity and inclusion, and maintaining focus on corporate ethics. We are managed and operated by the Board and executive officers of our general partner. All our employees, including our executive officers, are employees of Black Stone Natural Resources Management Company ("Black Stone Management").

Headcount. We rely principally on full-time employees but use independent contractors as needed to assist with special projects. As of December 31, 2025, Black Stone Management had 122 full-time employees and 7 contractors. Our largest departments are Accounting and Land Administration, which account for 37 and 23 respectively, of our full-time employee base. None of Black Stone Management's employees are represented by labor unions or covered by any collective bargaining agreements.

Recruiting. As a small, tight-knit group, our employees have broad responsibilities, and we encourage continuing development in their careers. When new opportunities arise within our organization, we have a multi-faceted approach to fill those positions including looking within our workforce for talent to fill those needs, asking for referrals from our team members (who understand the diverse skill sets, high energy and forward-thinking attitude that contributes to delivering exceptional results), posting open positions to our public-facing website, and working with recruiters who specialize in the areas of our vacancies.

Compensation. As part of our efforts to hire and retain highly qualified employees, we have structured compensation and benefits programs that, we believe, are extremely competitive and reward outstanding performance. In addition to the incentive programs in place for our named executive officers, which are described in detail in our proxy statement, we have structured a cash-bonus program for non-officer employees that is dependent on an employee's individual performance and our performance as a company. Certain employees also receive restricted-unit and performance-unit awards to encourage retention and align compensation with our company performance.

Healthcare and Other Benefits. We provide a robust suite of benefits to our employees covering all aspects of life, including 401(k) matching, medical-insurance options, and programs to encourage and support the whole person, including physical, mental and emotional, financial, social, career, and community service initiatives. Within these listed programs we provide, free to all employees, dental and vision insurance covering an employee's entire family, caregiver support benefits, a personal financial wellness program, a tuition-reimbursement program, a building-provided fitness center, employee health care advocacy services, a wellness program providing employees the ability to earn lifestyle rewards for participating in healthy activities as well as a recognition program to celebrate milestone service awards and other moments of excellence.

Hybrid Work Environment. The majority of our employees have work flexibility which allows for work outside of the office on Monday and Friday, and requires work in the office on Tuesday through Thursday during core business hours. This arrangement allows employees to have a greater work-life balance, and we believe the ability to work in a hybrid environment, as well as our robust compensation and benefits program, allow us to retain and recruit top-quality employees.

Facilities

Our principal office location is in Houston, Texas and consists of 55,862 square feet of leased space.

ITEM 1A. RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. If any of the following risks were to occur, our financial condition, results of operations, cash flows, and ability to make distributions could be materially adversely affected. In that case, we might not be able to make distributions on our common units, the trading price of our common units could decline, and holders of our units could lose all or part of their investment.

Cash Distributions

We may not generate sufficient cash from operations to pay distributions on our common units. If we make distributions, the holders of our Series B cumulative convertible preferred units have priority with respect to rights to share in those distributions over our common unitholders for so long as our Series B cumulative convertible preferred units are outstanding.

We may not generate sufficient cash from operations each quarter to pay distributions to our common unitholders. Our Series B cumulative convertible preferred unitholders have priority with respect to rights to share in distributions over our common unitholders for so long as our Series B cumulative convertible preferred units are outstanding. Furthermore, our partnership agreement does not require us to pay distributions to our common unitholders on a quarterly basis or otherwise. The amount of cash to be distributed each quarter will be determined by the Board.

The amount of cash we are able to distribute each quarter principally depends upon the amount of revenues we generate, which are largely dependent upon the prices that our operators realize from the sale of oil and natural gas. The actual amount of cash we are able to distribute each quarter will be reduced by principal and interest payments on our outstanding debt, working-capital requirements, and other cash needs. In addition, we may restrict distributions, in whole or in part, to fund acquisitions and participation in working interests. If over the long term we do not retain cash for capital expenditures in amounts necessary to maintain our asset base, a portion of future distributions will represent distribution of our assets and the value of our common units could be adversely affected. Withholding cash for our capital expenditures may have an adverse impact on the cash distributions in the quarter in which amounts are withheld.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, please read Part II, Item 5. "Market for Registrant's Common Equity, Related Unitholder Matters, and Issuer Purchases of Equity Securities — Cash Distribution Policy."

The amount of cash we distribute to holders of our units depends primarily on our cash generated from operations and not our profitability, which may prevent us from making cash distributions during periods when we record net income.

The amount of cash we distribute depends primarily upon our cash generated from operations and not solely on profitability, which may be affected by non-cash items. As a result, we may make cash distributions during periods in which we record net losses for financial accounting purposes and may be unable to make cash distributions during periods in which we record net income.

Price of Oil and Natural Gas

The volatility of oil and natural gas prices due to factors beyond our control greatly affects our financial condition, results of operations, and cash distributions to unitholders.

Our revenues, operating results, cash distributions to unitholders, and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty, and a variety of additional factors that are beyond our control, including:

- the domestic and foreign supply of and demand for oil and natural gas;
- market expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing, and delivering oil and natural gas;
- the price and quantity of foreign imports and exports of oil and natural gas;

- political and economic conditions in oil producing regions, including the Middle East, Africa, South America, including Venezuela, and Russia;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- trading in oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes, including tariffs and other controls on imports or exports of goods, including energy products;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- global geopolitical conflicts and developments, including the ongoing conflict in Ukraine, hostilities in the Middle East, the evolving situation in Venezuela and the relationships between the United States and other countries, such as China and Russia;
- the proximity, cost, availability, and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. The table below demonstrates such volatility for the periods presented.

	Year Ended December 31, 2025		During the Five Years Prior to December 31, 2025		As of December 31,		
	High	Low	High[2]	Low[3]	2025	2024	2023
WTI spot crude oil ($/Bbl)[1]	$ 73.79	$ 57.26	$ 123.64	$ 47.47	$ 57.26	$ 72.44	$ 71.89
Henry Hub spot natural gas ($/MMBtu)[1]	$ 9.86	$ 2.65	$ 23.86	$ 1.21	$ 4.00	$ 3.40	$ 2.58

[1] Source: EIA
[2] High prices for WTI and Henry Hub were in 2022 and 2021, respectively.
[3] Low prices for WTI and Henry Hub were in 2021 and 2024, respectively.

Any prolonged substantial decline in the price of oil and natural gas will likely have a material adverse effect on our financial condition, results of operations, and cash distributions to unitholders. We may use various derivative instruments in connection with anticipated oil and natural gas sales to minimize the impact of commodity price fluctuations. However, we cannot always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, or our hedges are not effective, our results of operations and financial position may be diminished.

In addition, lower oil and natural gas prices may also reduce the amount of oil and natural gas that can be produced economically by our operators. This scenario may result in our having to make substantial downward adjustments to our estimated proved reserves, which could negatively impact our borrowing base and our ability to fund our operations. If this occurs or if production estimates change or exploration or development results deteriorate, successful efforts method of accounting principles may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Our operators could also determine during periods of low commodity prices to shut in or curtail production from wells on our properties. In addition, they could determine during periods of low commodity prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, they may abandon any well if they reasonably believe that the well can no longer produce oil or natural gas in commercially paying quantities.

Approximately 52% of our 2025 oil and natural gas revenues were derived from oil and condensate sales. Any future decreases in prices of oil may adversely affect our cash generated from operations, results of operations, financial position, and our ability to pay quarterly distributions on our common units, perhaps materially.

During the ten years prior to December 31, 2025, WTI market prices at Cushing, Oklahoma have ranged from a high of $123.64 per Bbl in 2022 to a low of $8.91 per Bbl in 2020. On December 31, 2025, the last trading day of 2025, the WTI spot market price of oil was $57.26. The changes in the price of oil have been caused by many factors, including periods of increasing U.S. oil production from unconventional (shale) reserves, periods of investment restraint from U.S. oil and natural gas producers, actions taken by members of the Organization of the Petroleum Exporting Countries and its broader partners ("OPEC+"), and geopolitical conflicts and developments. If prices for oil are depressed for an extended period of time or there are future declines, we may be required to write down the value of our oil and natural gas properties and some of our undeveloped locations may no longer be economically viable. In addition, sustained low prices for oil may negatively impact the value of our estimated proved reserves and the amount that we are allowed to borrow under our Credit Facility and reduce the amounts of cash we would otherwise have available to pay expenses, fund capital expenditures, make distributions to our unitholders, and service our indebtedness.

Approximately 48% of our 2025 oil and natural gas revenues were derived from natural gas and natural gas liquids sales. Any future decreases in prices of natural gas may adversely affect our cash generated from operations, results of operations, financial position, and our ability to pay quarterly distributions on our common units, perhaps materially.

During the ten years prior to December 31, 2025, natural gas prices at Henry Hub have ranged from a high of $23.86 per MMBtu in 2021 to a low of $1.21 per MMBtu in 2024. On December 31, 2025, the last trading day of 2025, the Henry Hub spot market price of natural gas was $4.00 per MMBtu. The changes in the price of natural gas have been caused by many factors, including periods of increasing U.S. natural gas production from unconventional (shale) reserves, periods of investment restraint from U.S. oil and natural gas producers, seasonal changes in demand for heating by residential and commercial customers, and levels of U.S. natural gas exports. If prices for natural gas are depressed for an extended period of time or there are future declines, we may be required to write down the value of our oil and natural gas properties and some of our undeveloped locations may no longer be economically viable. In addition, sustained low prices for natural gas may negatively impact the value of our estimated proved reserves and the amount that we are allowed to borrow under our Credit Facility and reduce the amounts of cash we would otherwise have available to pay expenses, make distributions to our unitholders, and service our indebtedness.

Trade policies, such as tariffs, could adversely affect our operations, costs, and business

Any actions taken by the United States' federal government that restrict or otherwise impact the economics of trade—including tariffs, trade barriers, or other similar measures—could have the potential to disrupt existing supply chains and trigger retaliatory efforts by other countries, including the imposition of tariffs, raising taxation, setting foreign exchange or capital controls, or establishing embargos, sanctions, or other import/export restrictions, thereby negatively impacting our business, both directly and indirectly. These developments, or the perception that more of them could occur, may materially adversely affect the global economy and stability of global financial markets, potentially reducing trade and depressing economic activity. Such changes in international trade policies may result in direct impact to our business or that of our operators through increased costs, changes in business prospects or operating results, which could adversely affect our financial condition. The extent of such impacts cannot be predicted at this time.

Production

Unless we replace the oil and natural gas produced from our properties, our cash generated from operations and our ability to make distributions to our common unitholders could be adversely affected.

Producing oil and natural gas wells are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and our operators' production thereof and our cash generated from operations and ability to make distributions are highly dependent on the successful development and exploitation of our reserves. The production decline rates of our properties may be significantly higher than estimated if the wells on our properties do not produce as expected. We may also not be able to find, acquire, or develop additional reserves to replace the current and future production of our properties at economically acceptable terms, which would adversely affect our business, financial condition, results of operations, and cash distributions to our common unitholders.

We either have little or no control over the timing of future drilling with respect to our mineral and royalty interests and non-operated working interests.

Our proved undeveloped reserves may not be developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations, and the decision to pursue development of a proved undeveloped drilling location will be made by the operator and not by us. The reserve data included in the reserve report of our engineer assume that substantial capital expenditures are required to develop the reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled, or that the results of the development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop our reserves, or decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our undeveloped reserves as unproved reserves.

Project areas on our properties, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Project areas on our properties are in various stages of development, ranging from project areas with current drilling or production activity to project areas that have limited drilling or production history. If the wells in the process of being completed do not produce sufficient revenues or if dry holes are drilled, our financial condition, results of operations, and cash distributions to unitholders may be adversely affected.

The unavailability, high cost, or shortages of rigs, equipment, raw materials, supplies, or personnel may restrict or result in increased costs for operators related to developing and operating our properties.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials, supplies, and personnel. When shortages occur, the costs and delivery times of rigs, equipment, and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. In accordance with customary industry practice, our operators rely on independent third-party service providers to provide many of the services and equipment necessary to drill new wells. If our operators are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer. Shortages of drilling rigs, equipment, raw materials, supplies, personnel, trucking services, tubulars, fracking and completion services, and production equipment could delay or restrict our operators' exploration and development operations, which in turn could have a material adverse effect on our financial condition, results of operations, and cash distributions to unitholders.

The marketability of oil and natural gas production is dependent upon transportation, pipelines, and refining facilities, which neither we nor many of our operators control. Any limitation in the availability of those facilities could interfere with our or our operators' ability to market our or our operators' production and could harm our business.

The marketability of our or our operators' production depends in part on the availability, proximity, and capacity of pipelines, tanker trucks, and other transportation methods, and processing and refining facilities owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage, or lack of available capacity on these systems, tanker truck availability, and extreme weather conditions. Also, the shipment of our or our operators' oil and natural gas on third-party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we or our operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation, processing, or refining-facility capacity could reduce our or our operators' ability to market oil and natural gas production and have a material adverse effect on our financial condition, results of operations, and cash distributions to unitholders. Our or our operators' access to transportation options and the prices we or our operators receive can also be affected by federal and state regulation—including regulation of production, transportation, and pipeline safety—as well by general economic conditions and changes in supply and demand. In addition, the third parties on whom we or our operators rely for transportation services are subject to complex federal, state, tribal, and local laws that could adversely affect the cost, manner, or feasibility of conducting our business.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries, and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates, and the timing of development expenditures may be incorrect. Our estimates of proved reserves and related valuations as of December 31, 2025, 2024, and 2023 were prepared by NSAI, a third-party petroleum engineering firm, which conducted a detailed review of our properties for the period covered by its reserve report using information provided by us. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing, and production. Also, certain assumptions regarding future oil and natural gas prices, production levels, and operating and development costs may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves and future cash generated from operations. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas that are ultimately recovered being different from our reserve estimates.

The estimates of reserves as of December 31, 2025, 2024, and 2023 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the years ended December 31, 2025, 2024, and 2023, respectively, in accordance with the SEC guidelines applicable to reserve estimates for those periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage.

The results of exploratory drilling in shale plays will be subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

Our operators use the latest drilling and completion techniques in their operations, and these techniques come with inherent risks, including being unable to land the well bore in the desired drilling zone and being unable to fracture stimulate the planned number of stages, and being unable to run tools through the well bore. In addition, to the extent our operators engage in horizontal drilling, those activities may adversely affect their ability to successfully drill in identified vertical drilling locations. Furthermore, certain of the new techniques that our operators may adopt, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before these wells begin producing. The results of drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently our operators will be less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our operators' drilling results are weaker than anticipated or they are unable to execute their drilling program on our properties, our operating and financial results in these areas may be lower than we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline, and our results of operations and cash distributions to unitholders could be adversely affected.

We depend on various unaffiliated operators for all exploration, development, and production on the properties underlying our mineral and royalty interests and non-operated working interests. Substantially all our revenue is derived from the sale of oil and natural gas production from producing wells in which we own a royalty interest or a non-operated working interest. A reduction in the expected number of wells to be drilled on our acreage by these operators or the failure of our operators to adequately and efficiently develop and operate our acreage could have an adverse effect on our results of operations.

Our assets consist of mineral and royalty interests and non-operated working interests. For the year ended December 31, 2025, we received revenue from over 1,000 operators. The failure of our operators to adequately or efficiently perform operations or an operator's failure to act in ways that are in our best interests could reduce production and revenues. Our operators are often not obligated to undertake any development activities other than those required to maintain their leases on our acreage. In the absence of a specific contractual obligation, any development and production activities will be subject to their reasonable discretion. Our operators could determine to drill and complete fewer wells on our acreage than is currently expected. The success and timing of drilling and development activities on our properties, and whether the operators elect to drill any additional wells on our acreage, depends on a number of factors largely outside of our control, including:

- the capital costs required for drilling activities by our operators, which could be significantly more than anticipated;
- the ability of our operators to access capital;
- prevailing commodity prices;

- the availability of suitable drilling equipment, production and transportation infrastructure, and qualified operating personnel;
- the operators’ expertise, operating efficiency, and financial resources;
- approval of other participants in drilling wells;
- the operators’ expected return on investment in wells drilled on our acreage as compared to opportunities in other areas;
- the selection of technology;
- the selection of counterparties for the marketing and sale of production; and
- the rate of production of the reserves.

The operators may elect not to undertake development activities, or may undertake these activities in an unanticipated fashion, which may result in significant fluctuations in our results of operations and cash distributions to our unitholders. Sustained reductions in production by the operators on our properties may also adversely affect our results of operations and cash distributions to unitholders.

Cessation or protracted slowdown of activity in the Shelby Trough area could adversely affect our results of operations.

In 2025, we generated 13% of our royalty revenues and 14% of our working interest revenues from three operators in the Shelby Trough area of the Haynesville play in East Texas, where we own a concentrated, relatively high-interest royalty position. Only one of these operators has an active drilling program on this acreage. Geographic and operator concentration heightens the effect of operational risks, including:

- operators’ diversion of drilling capital to other areas, where our royalty interest is less meaningful or nonexistent;
- adverse changes to the operators’ financial positions;
- unanticipated geographic or environmental constraints in the Shelby Trough;
- delay or cancellation of construction or operation of LNG export facilities in the Gulf of Mexico; or
- delay, cancellation, or reduced demand from planned data centers.

If any of these risks are realized, production may decrease, reducing cash generated from operations and cash available for distribution.

We may experience delays in the payment of royalties and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy.

A failure on the part of the operators to make royalty payments gives us the right to terminate the lease, repossess the property, and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement operator. However, we might not be able to find a replacement operator and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to bankruptcy proceedings, in which case our right to enforce or terminate the lease for any defaults, including non-payment, may be substantially delayed or otherwise impaired.

Access to Capital and Financing

Our Credit Facility has substantial restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions.

Our Credit Facility limits the amounts we can borrow to a borrowing base amount, as determined by the lenders at their sole discretion based on their valuation of our proved reserves and their internal criteria. The borrowing base is redetermined at least semi-annually, and the available borrowing amount could be decreased as a result of such redeterminations. Decreases in the available borrowing amount could result from declines in oil and natural gas prices, operating difficulties or increased costs, decreases in reserves, lending requirements, or regulations or certain other circumstances. As of December 31, 2025, we had $154.0 million outstanding borrowings and the aggregate maximum credit amounts of the lenders were $1.0 billion. In October 2025, we amended the Credit Facility to extend the maturity date from October 31, 2027 to October 31, 2030 and remove the adjustment applied to secured overnight financing rate ("SOFR") loans. Concurrent with the Credit Facility amendment, the borrowing base under the Credit Facility was reaffirmed at $580.0 million and we elected to maintain cash commitments under the Credit Facility at $375.0 million. The next semi-annual redetermination is scheduled for April 2026. A future decrease in our borrowing base could be substantial and could be to a level below our then-outstanding borrowings. Outstanding borrowings in excess of the borrowing base are required to be repaid in five equal monthly payments, or we are required to pledge other oil and natural gas properties as additional collateral, within 30 days following notice from the administrative agent of the new or adjusted borrowing base. If we do not have sufficient funds on hand for repayment, we may be required to seek a waiver or amendment from our lenders, refinance our Credit Facility, or sell assets, debt, or equity. We may not be able to obtain such financing or complete such transactions on terms acceptable to us or at all. Failure to make the required repayment could result in a default under our Credit Facility, which could materially adversely affect our business, financial condition, results of operations, and distributions to our unitholders.

The operating and financial restrictions and covenants in our Credit Facility restrict, and any future financing agreements likely will restrict, our ability to finance future operations or capital needs, engage in, expand, or pursue our business activities, or pay distributions. Our Credit Facility restricts, and any future Credit Facility likely will restrict, our ability to:

- incur indebtedness;
- grant liens;
- make certain acquisitions and investments;
- enter into hedging arrangements;
- enter into transactions with our affiliates;
- make distributions to our unitholders; or
- enter into a merger, consolidation, or sale of assets.

Our Credit Facility restricts our ability to make distributions to unitholders or to repurchase units unless after giving effect to such distribution or repurchase, there is no event of default under our Credit Facility and our outstanding borrowings are not in excess of our borrowing base. While we currently are not restricted by our Credit Facility from declaring a distribution, we may be restricted from paying a distribution in the future.

We also are required to comply with certain financial covenants and ratios under the Credit Facility. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, such as reduced oil and natural gas prices. If we violate any of the restrictions, covenants, ratios, or tests in our Credit Facility, a significant portion of our indebtedness may become immediately due and payable, our ability to make distributions will be inhibited, and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our Credit Facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our Credit Facility, the lenders can seek to foreclose on our assets.

We expect to distribute a substantial majority of the cash we generate from operations each quarter, which could limit our ability to grow and make acquisitions.

We expect to distribute a substantial majority of the cash we generate from operations each quarter. As a result, we will have limited cash generated from operations to reinvest in our business or to fund acquisitions, and we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and growth capital expenditures. If we are unable to finance growth externally, our distribution policy will significantly impair our ability to grow.

If we issue additional units in connection with any acquisitions or growth capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. Other than limitations restricting our ability to issue units ranking senior or on parity with our Series B cumulative convertible preferred units, there are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units with respect to distributions. The incurrence of additional commercial borrowings or other debt to finance our growth would result in increased interest expense and required principal repayments, which, in turn, may reduce the cash that we have available to distribute to our unitholders. Please read Part II, Item 5. "Market for Registrant's Common Equity, Related Unitholder Matters, and Issuer Purchases of Equity Securities — Cash Distribution Policy."

Our operators' development activities on our leases, funding our non-operated working interests, and acquisitions will require substantial capital, and we and our operators may be unable to obtain needed capital or financing on satisfactory terms or at all.

The oil and natural gas industry is capital intensive. Most of our operators are dependent on the availability of external debt and equity financing sources to maintain their drilling programs. If those financing sources are not available to the operators on favorable terms or at all, then we expect the development of our properties to be adversely affected. If the development of our properties is adversely affected, then revenues from our mineral and royalty interests and non-operated working interests may decline.

In the past, we have made substantial capital expenditures in connection with the acquisition of mineral and royalty interests and, to a lesser extent, participation in our non-operated working interests. To date, we have financed capital expenditures primarily with funding from cash generated by operations, limited borrowings under our Credit Facility, farmout agreements, and the issuance of equity securities.

While we are currently focused on organic growth of our existing assets and have farmed out most of our non-operated working interests, we expect to make opportunistic acquisitions to complement our existing acreage positions and may need access to capital for those activities in the future. In those cases, we may restrict distributions to fund acquisitions and participation in our working interests but eventually we may need capital in excess of the amounts we retain in our business or borrow under our Credit Facility. We cannot assure you that we will be able to access external capital on terms favorable to us or at all. If we are unable to fund our capital requirements, we may be unable to complete acquisitions, take advantage of business opportunities, or respond to competitive pressures, any of which could have a material adverse effect on our results of operation and cash distributions to unitholders.

Acquisitions

Any acquisitions of additional mineral and royalty interests will be subject to substantial risks.

Our principal growth strategy focuses on adding reserves on our existing properties. From time to time, however, we may acquire mineral and royalty interests. If we do make acquisitions that we believe will increase our cash generated from operations, these acquisitions may nevertheless result in a decrease in our cash distributions per unit. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, prices, revenues, capital expenditures, operating expenses, and costs;
- a decrease in our liquidity by using a significant portion of our cash generated from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses, or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- mistaken assumptions about the overall cost of equity or debt;
- our ability to obtain satisfactory title to the assets we acquire;
- an inability to hire, train, or retain qualified personnel to manage and operate our growing business and assets;
- investments in seismic and other subsurface data may not identify commercially viable prospects or support successful development or acquisitions; and
- the occurrence of other significant changes, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation, or restructuring charges.

Environmental, Legal and Regulatory Risks

Conservation measures, technological advances, and general concern about the environmental impact of the production and use of fossil fuels could materially reduce demand for oil and natural gas and adversely affect our results of operations and the trading market for our common units.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy, and energy-generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations, and cash distributions to unitholders. It is also possible that the concerns about the production and use of fossil fuels will reduce the number of investors willing to own our common units, adversely affecting the market price of our common units.

Oil and natural gas operations are subject to various governmental laws and regulations. Compliance with these laws and regulations can be burdensome and expensive, and failure to comply could result in significant liabilities, which could reduce cash distributions to our unitholders.

Operations on the properties in which we hold interests are subject to various federal, state, and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include drilling operations, production and distribution activities, discharges or releases of pollutants or wastes, plugging and abandonment of wells, maintenance and decommissioning of other facilities, the spacing of wells, unitization and pooling of properties, and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and natural gas. In addition, the production, handling, storage, and transportation of oil and natural gas, as well as the remediation, emission, and disposal of oil and natural gas wastes, by-products thereof, and other substances and materials produced or used in connection with oil and natural gas operations, are subject to regulation under federal, state, and local laws and regulations primarily relating to protection of worker health and safety, natural resources, and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, or criminal penalties, permit revocations, requirements for additional pollution controls, and injunctions limiting or prohibiting some or all of the operations on our properties. Moreover, these laws and regulations have generally imposed increasingly strict requirements related to water use and disposal, air pollution control, and waste management.

Laws and regulations governing exploration and production may also affect production levels. Our operators must comply with federal and state laws and regulations governing conservation matters, including:

- provisions related to the unitization or pooling of the oil and natural gas properties;
- the establishment of maximum rates of production from wells;
- the spacing of wells;
- the plugging and abandonment of wells; and
- the removal of related production equipment.

Additionally, federal and state regulatory authorities may expand or alter applicable pipeline-safety laws and regulations. Compliance with such regulations may require increased capital costs for third-party oil and natural gas transporters. These transporters may attempt to pass on such costs to our operators, which in turn could affect profitability on the properties in which we own mineral and royalty interests.

Our operators must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the operators of our properties are shippers on interstate pipelines, they must comply with the tariffs of those pipelines and with federal policies related to the use of interstate capacity.

Our operators may be required to make significant expenditures to comply with the governmental laws and regulations described above and may be subject to potential fines and penalties if they are found to have violated these laws and regulations. We believe the general trend of more expansive and stricter environmental legislation and regulations will continue. Please read Part I, Items 1 and 2. “Business and Properties — Environmental Matters” for a description of the laws and regulations that affect our operators and that may affect us. These and other potential regulations could increase the operating costs of our operators and delay production, which could adversely affect the amount of cash available for distribution to our unitholders.

Louisiana mineral servitudes are subject to reversion to the surface owner after ten years’ nonuse.

We own mineral servitudes covering several hundred thousand acres in Louisiana. A mineral servitude is created in Louisiana when the mineral rights are separated from the ownership of the surface, whether by sale or reservation. These mineral servitudes, once created, are subject to a ten-year prescription of nonuse. During the ten-year period, the mineral-servitude owner has to conduct good-faith operations on the servitude for the discovery and production of minerals, or the mineral servitude “prescribes,” and the mineral rights associated with that servitude revert to the surface owner. A good-faith operation for the discovery and production of minerals, even one resulting in a dry hole, conducted within the ten-year period will interrupt the prescription of nonuse and restart the running of the ten-year prescriptive period. If the operation results in production, prescription is interrupted as long as the production continues or operations are conducted in good faith to secure or restore production. If any of our mineral servitudes are prescribed by operation of Louisiana law, our operating results may be adversely affected.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs, additional operating restrictions or delays, and fewer potential drilling locations.

Our operators engage in hydraulic fracturing. Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations, including shales. The process involves the injection of water, sand, and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Numerous federal and state laws and regulations affect our operators' ability to conduct hydraulic fracturing. Please read Part I, Items 1 and 2. "Business and Properties — Environmental Matters — Hydraulic Fracturing" for a description of the laws and regulations that affect our operators and that may affect us.

There has been controversy regarding hydraulic fracturing with regard to increased risks of induced seismicity, the use of fracturing fluids, impacts on drinking water supplies, use of water, and the potential for impacts to surface water, groundwater, and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic-fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, those laws could make it more difficult or costly for our operators to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities on our properties could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, and also to attendant permitting delays and potential increases in costs. Legislative changes could cause operators to incur substantial compliance costs. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Operating hazards and uninsured risks may result in substantial losses to us or our operators, and any losses could adversely affect our results of operations and cash distributions to unitholders.

We may be secondarily liable for damage to the environment caused by our operators. The operations of our operators will be subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses, and environmental hazards such as oil spills, natural gas leaks and ruptures, or discharges of toxic gases. In addition, their operations will be subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage, or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to our operators due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations, and repairs required to resume operations.

In accordance with what we believe to be customary industry practice, we maintain insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations, or cash distributions to unitholders. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

We may not have coverage if we are unaware of a sudden and accidental pollution event and unable to report the “occurrence” to our insurance providers within the time frame required under our insurance policy. We do not have, and do not intend to obtain, coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure our unitholders that the insurance coverage will be adequate to cover claims that may arise or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations, and cash distributions to unitholders.

Increased attention to environmental, social and governance (ESG) matters may impact our business.

Increased attention to, and sometimes conflicting social expectations on, companies to address climate change, investor and societal expectations regarding ESG disclosures, and increased consumer demand for alternative forms of energy may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on our unit price and access to capital markets. Increased attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us or our operators. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation or contribution to the asserted damage, or other mitigating factors. Please read Part I, Items 1 and 2. "Business and Properties — Environmental Matters" for additional information on related developments that may affect us, our operators, and/or the oil and gas sector more generally.

Any new laws or regulations imposing requirements on our business related to the disclosure of climate-related risks may result in reputational harms among certain stakeholders if they disagree with our approach to mitigating climate-related risks, increased compliance costs, and increased costs of and restrictions on access to capital to the extent we do not meet any climate-related expectations of requirements of financial institutions. For example, California has enacted laws requiring additional disclosure with respect to certain climate-related risks and GHG emissions reduction claims. Other states are expected to follow. Non-compliance with these laws, to the extent applicable, may result in the imposition of substantial fines or penalties.

In addition, certain organizations that provide information, ratings or proxy advisory services to investors on corporate governance and related matters have developed processes for evaluating companies on their approach to ESG matters. Such ratings or recommendations are used by some investors to inform their investment and voting decisions. While such ratings or recommendations do not impact all investors' investment or voting decisions, unfavorable ESG ratings or recommendations may lead to negative investor sentiment toward us and to the diversion of investment which could have a negative impact on our unit price and/or our access to and costs of capital. Additionally, certain financial institutions may decide not to provide funding or insurance for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital or the ability to complete projects.

Additionally, certain public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, have been subject to heightened scrutiny from public and governmental authorities related to the risk of potential "greenwashing," i.e., misleading information or false claims overstating potential ESG benefits. Any alleged claims of greenwashing against us or others in our industry may lead to increased litigation risks and foster negative sentiment and diversion of investments.

Finally, certain employment or business practices and social initiatives are the subject of scrutiny by both those calling for the continued advancement of such policies, as well as those who believe they should be curbed, including government actors, and the complex regulatory and legal frameworks applicable to such initiatives continue to evolve. We cannot be certain of the impact of such regulatory, legal and other developments on our business. More recent political developments could mean that we face increasing criticism or litigation risks from certain "anti-ESG" parties, including various governmental agencies. Consideration of ESG-related factors in our decision-making could be subject to increasing scrutiny and objection from such anti-ESG parties and increase litigation risks from private parties and governmental authorities.

Key Persons

We rely on a few key individuals whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of individuals. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of our executive team could disrupt our business, and if we are unable to manage an orderly transition, our business may be adversely affected.

Further, we do not maintain "key person" life insurance policies on any of our executive team or other key personnel. As a result, we are not insured against any losses resulting from the death of these key individuals.

Title Defects

Title to the properties in which we have an interest may be impaired by title defects.

No assurance can be given that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Risks to Unitholders under Our Partnership Agreement

The Board may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all on our common units. If we make distributions, our Series B cumulative convertible unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our Series B cumulative convertible preferred units are outstanding.

Our partnership agreement generally provides that any distributions are paid each quarter as follows: (i) first, to the holders of Series B cumulative convertible preferred units in an amount equal to 7.0% of the face amount of the preferred units per annum, through November 27, 2023, then adjusting on November 28, 2023 and readjusting every two years thereafter, to a rate equal to the greater of (a) the rate in effect immediately prior to the relevant readjustment and (b) the 10-year Treasury Rate as of such readjustment date plus 5.5% per annum (which rate adjusted to 9.8% effective November 28, 2023 and remained the same at 9.8% for November 28, 2025), and (ii) second, to the holders of common units. However, the Board could elect not to pay distributions for one or more quarters or at all. Please read Part II, Item 5. "Market for Registrant's Common Equity, Related Unitholder Matters, and Issuer Purchases of Equity Securities — Cash Distribution Policy."

Our partnership agreement does not require us to pay any distributions at all on our common units. Accordingly, investors are cautioned not to place undue reliance on the permanence of any distribution policy in making an investment decision. Any modification or revocation of our cash distribution policy could substantially reduce or eliminate the amounts of distributions to our unitholders. The amount of distributions we make, if any, and the decision to make any distribution at all will be determined by the Board. If we make distributions, our Series B cumulative convertible preferred unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our Series B cumulative convertible preferred units are outstanding. Please read Part II, Item 5. "Market for Registrant's Common Equity, Related Unitholder Matters, and Issuer Purchases of Equity Securities — Cash Distribution Policy — Series B Cumulative Convertible Preferred Units."

Our partnership agreement eliminates the fiduciary duties that might otherwise be owed to the partnership and its partners by our general partner and its directors and executive officers under Delaware law.

Our partnership agreement contains provisions that eliminate the fiduciary duties that might otherwise be owed by our general partner and its directors and executive officers. For example, our partnership agreement provides that our general partner and its directors and executive officers have no duties to the Partnership or its partners except as expressly set forth in the partnership agreement. In place of default fiduciary duties, our partnership agreement imposes a contractual standard requiring our general partner and its directors and executive officers to act in good faith, meaning they cannot cause the general partner to take an action that they subjectively believe is adverse to our interests. Such contractual standards allow our general partner and its directors and executive officers to manage and operate our business with greater flexibility and to subject the actions and determinations of our general partner and its directors and executive officers to lesser legal or judicial scrutiny than would be the case if state law fiduciary standards were applicable.

Our partnership agreement restricts the situations in which remedies may be available to our unitholders for actions taken that might constitute breaches of duty under applicable Delaware law and breaches of the contractual obligations in our partnership agreement.

Our partnership agreement restricts the potential liability of our general partner and its directors and executive officers to our unitholders. For example, our partnership agreement provides that our general partner and its directors and executive officers will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in willful misconduct or fraud or, with respect to any criminal conduct, with the knowledge that its conduct was unlawful.

Unitholders are bound by the provisions of our partnership agreement, including the provisions described above.

Our partnership agreement restricts the voting rights of unitholders owning 15% or more of our units, subject to certain exceptions.

Our 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 our predecessor prior to the IPO, their transferees, persons who acquired such units with the prior approval of 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 us or any conversion of the Series B cumulative convertible preferred units at our option or in connection with a change of control may not vote on any matter.

Our partnership agreement includes exclusive forum, venue, and jurisdiction provisions. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions, or proceedings, and submitting to the exclusive jurisdiction of Delaware courts.

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue, and jurisdiction provisions designating Delaware courts as the exclusive venue for all claims, suits, actions, or proceedings arising out of or relating in any way to the partnership agreement, brought in a derivative manner on behalf of the Partnership, asserting a claim of breach of a fiduciary or other duty owed by any director, officer, or other employee of the Partnership or the general partner, or owed by the general partner to the Partnership or the partners, asserting a claim arising pursuant to any provision of the Delaware Act, or asserting a claim governed by the internal affairs doctrine. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions, or proceedings and submitting to the exclusive jurisdiction of Delaware courts. If a dispute were to arise between a limited partner and us or our officers, directors, or employees, the limited partner may be required to pursue its legal remedies in Delaware, which may be an inconvenient or distant location and which is considered to be a more corporate-friendly environment.

We may issue additional common units and other equity interests without common unitholder approval, which would dilute holders of common units. However, subject to certain exceptions, our partnership agreement does not authorize us to issue units ranking senior to or at parity with our Series B cumulative convertible preferred units without Series B cumulative convertible preferred unitholder approval.

Under our partnership agreement, we are authorized to issue an unlimited number of additional interests, including common units, without a vote of the unitholders other than, in certain instances, approval of holders of our Series B cumulative convertible preferred units. Our issuance of additional common units or other equity interests of equal or senior rank will have the following effects:

- the proportionate ownership interest of common unitholders in us immediately prior to the issuance will decrease;
- the amount of cash distributions on each common unit may decrease;
- the ratio of our taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of the common units may decline.

However, subject to certain exceptions, our partnership agreement does not authorize us to issue securities having preferences or rights with priority over or on a parity with the Series B cumulative convertible preferred units with respect to rights to share in distributions, redemption obligations, or redemption rights without Series B cumulative convertible preferred unitholder approval.

Distributions to Unitholders; Price of Units and Other Risks

Actions taken by our general partner may affect the amount of cash generated from operations that is available for distribution to unitholders.

The amount of cash generated from operations available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;

- borrowings and repayment of current and future indebtedness;
- redemption of all or a portion of the Series B cumulative convertible preferred units;
- issuance of additional units; and
- the creation, reduction, or increase of reserves in any quarter.

In addition, borrowings by us do not constitute a breach of any duty owed by our general partner to our unitholders.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets.

As of December 31, 2025, we had 211,873,257 common units and 14,711,219 Series B cumulative convertible preferred units outstanding. Each holder may elect to convert all or any portion of its Series B cumulative convertible preferred units into common units on a one-for-one basis, subject to customary anti-dilution adjustments, an adjustment for any distributions that have accrued but not been paid when due, and certain other restrictions. Under certain conditions, we may elect to convert all or any portion of the Series B cumulative convertible preferred units into common units. As of December 31, 2025 and through the date of this filing, we had not met all such conditions and therefore were not eligible to exercise our conversion right for the Series B cumulative convertible preferred units. Sales by holders of a substantial number of our common units in the public markets, or the perception that these sales might occur, could have a material adverse effect on the price of our common units or impair our ability to obtain capital through an offering of equity securities.

Increases in interest rates may cause the market price of our common units to decline

An increase in interest rates may cause a corresponding decline in demand for equity investments in general, and in particular, for yield-based equity investments such as our common units. Any such increase in interest rates or reduction in demand for our common units resulting from other investment opportunities may cause the trading price of our common units to decline.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

Because we are a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. In addition, because we are a publicly traded partnership, the NYSE does not require us to obtain unitholder approval prior to certain unit issuances. Accordingly, unitholders will not have the same protections afforded to stockholders of certain corporations that are subject to all of the NYSE's corporate governance requirements.

If a unitholder is not an Eligible Holder, the common units of such unitholder may be subject to redemption.

We have adopted certain requirements regarding those investors who may own our units. Eligible Holders are limited partners (a) whose, or whose owners', U.S. federal income tax status does not have or is not reasonably likely to have a material adverse effect on the rates chargeable by us to customers and (b) whose ownership could not result in our loss of ownership in any material part of our assets, as determined by our general partner with the advice of counsel. If an investor is not an Eligible Holder, in certain circumstances as set forth in our partnership agreement, units held by such investor may be redeemed by us at the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Tax-Related Risks

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, and not being subject to a material amount of entity-level taxation. If the IRS were to treat us as a corporation for U.S. federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, then our cash distributions to common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we will be treated as a corporation for U.S. federal income tax purposes unless we satisfy the "qualifying income" requirement within Section 7704(d)(1)(E) of the Internal Revenue Code. Based upon our current operations and current Treasury Regulations, we believe that we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 21%, and would likely pay state income tax at varying rates. Distributions to our common unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions, or credits would flow through to our common unitholders. Because an entity-level tax would be imposed upon us as a corporation, cash distributions to our common unitholders would be substantially reduced. In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, and other forms of taxation. Imposition of any of those taxes may substantially reduce the cash distributions to our common unitholders. Therefore, treatment of us as a corporation or the assessment of a material amount of entity-level taxation would result in a material reduction in the anticipated cash generated from our operations and after-tax returns to our common unitholders, likely causing a substantial reduction in the value of our common units.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative, or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including proposals that would eliminate our ability to qualify for partnership tax treatment. Recent proposals have provided for the expansion of the qualifying income exception for publicly traded partnerships in certain circumstances and other proposals have provided for the total elimination of the qualifying income exception upon which we rely for our partnership tax treatment.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future.

Any modification to the U.S. federal income tax laws or interpretations thereof may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted or adopted. Any such changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of legislative, regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and natural gas extraction.

From time to time, legislation has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could increase costs or eliminate or postpone certain tax deductions that currently are available to us or our services providers with respect to oil and gas development. Any such changes could have an adverse effect on our financial position, results of operations, and cash flows.

If the IRS were to contest the U.S. federal income tax positions we take, it may adversely affect the market for our common units, and the costs of any such contest would reduce cash available for distribution to our common unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely affect the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our common unitholders and thus will be borne indirectly by our common unitholders.

If the IRS makes an audit adjustment to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case cash available for distribution to our common unitholders might be substantially reduced and our current and former common unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such common unitholders' behalf.

If the IRS makes an audit adjustment to our income tax return, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each common unitholder and former common unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our common unitholders and former common unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible, or effective in all circumstances. As a result, our current common unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such common unitholders did not own common units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties, and interest, cash available for distribution to our common unitholders might be substantially reduced and our current and former common unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustment that were paid on such common unitholders' behalf.

You, as a common unitholder, are required to pay taxes on your share of our income, even if you do not receive any cash distributions from us.

You will be required to pay U.S. federal income taxes and, in some cases, state and local income taxes, on your share of our taxable income, whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell your common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. In addition, because the amount realized includes a common unitholder’s share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

A substantial portion of the amount realized from the sale of your common units, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation recapture. Thus, you may recognize both ordinary income and capital loss from the sale of your common units if the amount realized on a sale of your common units is less than your adjusted basis in the common units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which you sell your common units, you may recognize ordinary income from our allocations of income and gain to you occurring prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of common units.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income.

If our "business interest" is subject to limitation under these rules, our unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, may be unrelated business taxable income and may be taxable to them. Additionally, all or part of any gain recognized by such tax-exempt organization upon a sale or other disposition of our units may be unrelated business taxable income and may be taxable to them. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. common unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. common unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our common unitholders and any gain from the sale of our common units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. common unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. common unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit. In addition to the withholding tax imposed on distributions of effectively connected income, distributions to a non-U.S. common unitholder will also be subject to a 10% withholding tax on the amount of any distribution in excess of our cumulative net income. As we do not compute our cumulative net income for such purposes due to the complexity of the calculation and lack of clarity in how it would apply to us, we intend to treat all of our distributions as being in excess of our cumulative net income for such purposes and subject to such 10% withholding tax. Accordingly, distributions to a non-U.S. common unitholder will be subject to a combined withholding tax rate equal to the sum of the highest applicable effective tax rate and 10%.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the "amount realized" by the transferor unless the transferor certifies that it is not a foreign person.

While the determination of a partner's "amount realized" generally includes any decrease of a partner's share of the partnership's liabilities, the Treasury Regulations provide that the "amount realized" on a transfer of an interest in a publicly traded partnership, such as our common units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner's share of a publicly traded partnership's liabilities. For a transfer of an interest in a publicly traded partnership that is effected through a broker, the obligation to withhold is imposed on the transferor's broker. Current and prospective non-U.S. common unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

We treat each purchaser of common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of our common units, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We generally prorate our items of income, gain, loss, and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss, and deduction among our common unitholders.

We generally prorate our items of income, gain, loss, and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the "Allocation Date"), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets, and (iii) in the discretion of the general partner, any other extraordinary item of income, gain, loss, or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss, and deduction among our common unitholders.

A common unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered to have disposed of those common units. If so, such common unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and could recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a common unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned common units. In that case, the common unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the common unitholder may recognize gain or loss from this disposition. Moreover, during the period of the loan, any of our income, gain, loss, or deduction with respect to those common units may not be reportable by the common unitholder and any cash distributions received by the common unitholder as to those common units could be fully taxable as ordinary income. Common unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

You, as a common unitholder, may be subject to state and local taxes and return filing requirements in jurisdictions where you do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, you likely will be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance, or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. We own assets and conduct business in several states, many of which impose a personal income tax and also impose income taxes on corporations and other entities. You may be required to file state and local income tax returns and pay state and local income taxes in these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state, and local tax returns and pay any taxes due in these jurisdictions. You should consult with your own tax advisors regarding the filing of such tax returns, the payment of such taxes and the deductibility of any taxes paid.

Although we believe our common unitholders are entitled to a 20% deduction related to qualified business income, application of the deduction to royalty income is not free from doubt.

An individual common unitholder is entitled to a deduction equal to 20% of his or her allocable share of our "qualified publicly traded partnership income." For purposes of the deduction, the term qualified publicly traded partnership income includes the net amount of such unitholder's allocable share of our income that is effectively connected to our U.S. trade or business activities. Although we expect most of our income to qualify for this deduction, application of these rules to income from mineral interests, such as royalty income, is not entirely clear. Our counsel has advised us that under current law our royalty income should qualify for the deduction, but no assurances can be given that the IRS will not challenge our treatment of royalty income as qualifying for the deduction.

General Risk Factors

The price of our common units may fluctuate significantly, and unitholders could lose all or part of their investment.

The market price of our common units may be influenced by many factors, some of which are beyond our control, including those described elsewhere in these risk factors.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud, and operate successfully as a publicly traded partnership. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future, or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act. For example, Section 404 requires us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

Various security risks, including cybersecurity threats, data breaches, and other disruptions, could significantly affect us.

Various security risks, including cyber attacks on businesses, have escalated in recent years. As one of the largest owners and managers of oil and natural gas mineral interests in the United States, we rely on electronic systems and networks to control and manage our business and have multiple layers of security to monitor, mitigate and manage these risks. However, these systems and networks, as well as our operators' systems and networks and third-party infrastructure and operations, such as pipelines and transportation facilities, may be subject to sophisticated and deliberate security attacks and security breaches, which could lead to the corruption or loss of sensitive and valuable data or other disruptions. If we or our operators were to experience an attack or a breach and security measures failed, the potential consequences to our businesses and the communities in which we operate could be significant, including the corruption or loss of sensitive and valuable data, legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, damage to our reputation, and other disruptions of our operations, any of which could adversely affect our business. In addition, as cyber attacks become increasingly sophisticated, and the regulatory framework for data privacy and security worldwide continues to evolve and develop, we may incur significant costs to modify, upgrade or enhance our security measures and we may face difficulties in fully anticipating or implementing adequate security measures or new or revised mandated processes and in generally mitigating potential harm. Further, any actual or perceived failure to comply with any new or existing laws, regulations and other obligations could result in fines, penalties or other liability.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Cybersecurity threats have become significantly more numerous and sophisticated over time, and the oil and gas industry in particular is highly targeted by malicious actors seeking to attack oil and gas infrastructure to disrupt operations. Because we are focused on mineral and royalty interests, we do not maintain any material physical infrastructure; nonetheless, being an industry participant increases our exposure to external attacks. We are committed to safeguarding our information technology systems and data and managing the risks associated with cybersecurity threats and implemented governance structures, processes, and technologies designed to prevent, detect, investigate, and mitigate any incident that could pose a cybersecurity risk.

Our Vice President, Information Technology ("VP IT"), with support from our Information Technology Infrastructure Team ("Infrastructure Team," which, together with the VP IT, make up the "Cybersecurity Team"), has primary responsibility for the assessment and management of risks from cybersecurity threats. Collectively, the four members of the Cybersecurity Team have over 75 years of cybersecurity-related experience in both the private and public sectors, including perimeter and internal network security, secure email gateway, B2B and B2C eCommerce, on-premises and cloud storage environment security, and ransomware protection solutions. In addition, members of the Cybersecurity Team have multiple network-security certifications relevant to the technologies we deploy.

Our Board of Directors provides oversight of our enterprise-wide risk management, which includes cybersecurity risk-management, and the Audit Committee assists the Board with oversight of cybersecurity matters. The VP IT reports on cybersecurity matters to senior management on a regular basis and to the Audit Committee at least annually, and more often if needed. The Audit Committee, in turn, makes periodic reports to the Board on relevant cybersecurity matters.

Our VP IT, the Director of our Infrastructure Team, and our General Counsel make up the Information Security Committee, which has the initial responsibility for the assessment of and response to cybersecurity incidents consistent with our formal incident-response plan. Pursuant to the incident-response plan, more serious incidents are escalated to other senior members of management, including the Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer, as well as to the Audit Committee and our external auditors, as appropriate.

We maintain the following processes to assess, identify, and manage risks from cybersecurity threats:

- *Ongoing Threat Assessment*. We maintain multiple threat intelligence subscriptions, and we monitor relevant cybersecurity resources on an ongoing basis to identify and anticipate potential threats to our network infrastructure.

- *Layered Security*. We use multiple tiers of security as part of our efforts to reduce our exposure to cyberattacks. We leverage and maintain perimeter network defense solutions to discourage network-intrusion attempts. Within our network, we leverage endpoint security and ransomware detection and prevention solutions, and we use continuous monitoring of alerts and activities to identify and respond to any irregularities that could be associated with threats.

- *Training and Awareness*. We conduct awareness training for our employees as part of our efforts to enable them to identify and report cybersecurity threats. We require cybersecurity training during employee and contractor onboarding, and we seek to reinforce the training through phishing tests on at least a quarterly basis as part of our efforts to reduce the potential for successful phishing and social-engineering attacks.

- *Cybersecurity Tool and Processes and Industry Standards*. We refer to industry standards, such as those issued by National Institutes of Standards and Technology ("NIST") and International Organization for Standardization ("ISO"), as part of our efforts to maintain best practices across our environment and we use various cybersecurity tools and processes designed to manage cybersecurity threats including network and systems authentication, network and infrastructure architecture security, endpoint security, and operating system patching.

- *Third-Party Network Security Assessments.* We engage a third-party consultant to conduct external penetration testing at least annually. Our cybersecurity processes are adjusted as needed based on the results of these assessments. The assessment results are reported to the Audit Committee and Board, and our external auditor reviews our cybersecurity solutions and posture on at least an annual basis.

- *Third-Party Risk Management*. We conduct information-security assessments before allowing sensitive data to be hosted by third parties. We also ensure SOC-1 or SOC-2 compliance for our third party providers, including our banking, payroll, and stock-plan administration relationships.

While we and our service providers have experienced cybersecurity incidents in the past, as of the date of this Annual Report, we are not aware of any previous cybersecurity threats that have materially affected or are reasonably likely to materially affect us, including our business strategy, results of operation, or financial condition. For more information regarding the risks we face, please read Part I, Item 1A. “Risk Factors—General Risk Factors—Various security risks, including cybersecurity threats, data breaches, and other disruptions, could significantly affect us.”

ITEM 3. 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 4. MINE SAFETY DISCLOSURES

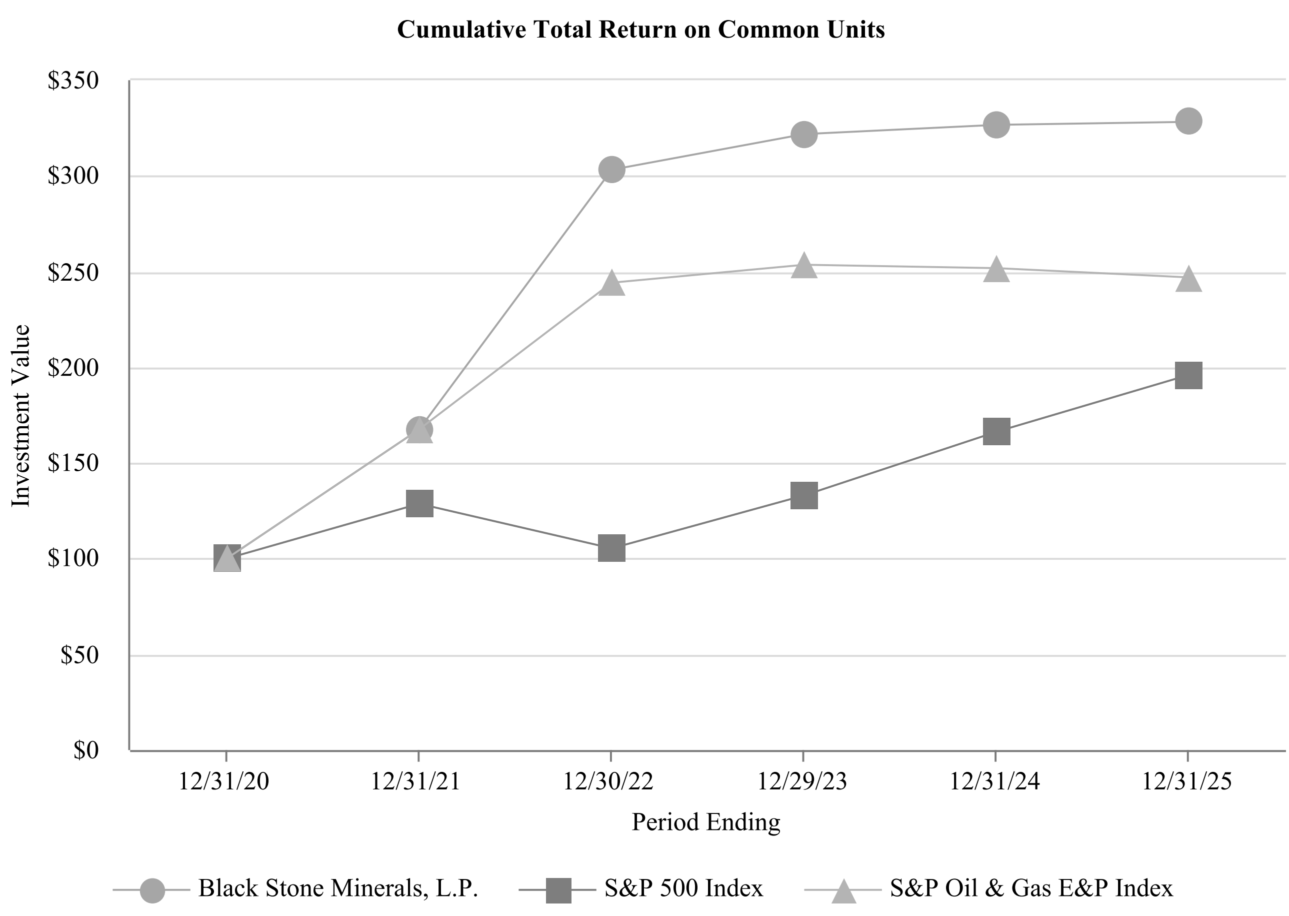
Not applicable.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are listed on the NYSE under the symbol "BSM." As of February 20, 2026, there were 212,333,793 common units outstanding held by 356 holders of record. Because many of our common units are held by brokers and other institutions on behalf of unitholders, we are unable to estimate the total number of unitholders represented by these holders of record. As of February 20, 2026, we also had outstanding 14,711,219 Series B cumulative convertible preferred units. There is no established public market in which the Series B cumulative convertible preferred units are traded.

Common Unit Performance Graph

The graph below compares the cumulative five-year total return to unitholders on our common units as compared to the cumulative five-year total returns on the S&P 500 index and the S&P Oil & Gas Exploration & Production index. The graph assumes that the value of the investment in our common units was $100.00 on December 31, 2020. Cumulative return is computed assuming reinvestment of distributions.



Comparison of Cumulative Total Return
Assumes Initial Investment of $100

	As of December 31,					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**
Black Stone Minerals, L.P.	$ 100.00	$ 167.55	$ 303.23	$ 321.86	$ 326.69	$ 328.25
S&P 500 Index	100.00	128.71	105.40	133.10	166.40	196.16
S&P Oil & Gas E&P Index	100.00	167.58	244.21	253.58	251.80	246.96

The information in this Annual Report appearing under the heading “Common Unit Performance Graph” is being furnished pursuant to Item 201(e) of Regulation S-K and shall not be deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934 ('the Exchange Act').

Securities Authorized for Issuance under Equity Compensation Plans

See the information incorporated by reference under “Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters” regarding securities authorized for issuance under our equity compensation plans.

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Cash Distribution Policy

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

- *first*, to the holders of the Series B cumulative convertible preferred units in an amount equal to 7.0% of the face amount of the preferred units per annum, through November 27, 2023, then adjusting on November 28, 2023 and readjusting every two years thereafter, to a rate equal to the greater of (i) the rate in effect immediately prior to the relevant readjustment and (ii) the 10-year Treasury Rate as of such readjustment date plus 5.5% per annum (which rate adjusted to 9.8% effective November 28, 2023 and remained the same at 9.8% for November 28, 2025); and

- *second*, to the holders of common units.

The amount of cash to be distributed each quarter will be determined by the Board following the end of that quarter after a review of our cash generated from operations for such quarter. We expect that we will distribute a substantial majority of the cash generated from our operations each quarter. The cash generated from operations for each quarter will generally equal our Adjusted EBITDA for the quarter, less cash needed for debt service, other contractual obligations, fixed charges, and reserves for future operating or capital needs that the Board may determine are appropriate. It is our intent, for at least the next several years, to finance most of our acquisitions and working interest capital needs with cash generated from operations, borrowings under our Credit Facility, and, in certain circumstances, proceeds from future equity and debt issuances. We may also borrow to make distributions to our unitholders where, for example, we believe that the distribution level is sustainable over the long term, but short-term factors may cause cash generated from operations to be insufficient to pay distributions at the then-current distribution levels on our common units. The Board can change the amount of the quarterly distributions, if any, at any time and from time to time. Our partnership agreement does not require us to pay cash distributions on a quarterly or other basis on our common units. Please read Part I, Item 1A. “Risk Factors — Risks Inherent in an Investment in Us — The Board may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all on our common units. If we make distributions, our Series B cumulative convertible preferred unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our Series B cumulative convertible preferred units are outstanding.” For a description of the relative rights and privileges of our Series B cumulative convertible preferred units to distributions, please read "Series B Cumulative Convertible Preferred Units" below.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

There is no guarantee that we will make cash distributions to our unitholders. Our cash distribution policy may be changed at any time by the Board and is subject to certain restrictions, including the following:

- Our common unitholders have no contractual or other legal right to receive cash distributions from us on a quarterly or other basis, and if distributions are paid, common unitholders will receive distributions only to the extent the distribution amount exceeds distributions that are required to be paid to our Series B cumulative convertible preferred unitholders.

- Among other covenants, our Credit Facility requires we maintain a ratio of total debt to EBITDAX of 3.5:1.0 or less and a current ratio of 1.0:1.0 or greater. Our Credit Facility restricts our distributions if there is a default under our Credit Facility, if the availability under our Credit Facility is less than 10% of the lender's commitments, or if total debt to EBITDAX is greater than 3.0. If we are unable to comply with these financial covenants or if we breach any other covenant under our Credit Facility or any future debt agreements, we could be prohibited from making distributions notwithstanding our stated distribution policy.

- Our general partner has the authority to establish cash reserves for the prudent conduct of our business, and the establishment of, or increase in, those reserves could result in a reduction in cash distributions to our unitholders. Our partnership agreement does not limit the amount of cash reserves that our general partner may establish. Any decision to establish cash reserves made by our general partner will be binding on our unitholders.

- Under Section 17-607 of the Delaware Act, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.

- We may lack sufficient cash to pay distributions to our unitholders due to shortfalls in cash generated from operations attributable to a number of operational, commercial, or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our outstanding debt, redemption of some or all of our Series B cumulative convertible preferred units, working-capital requirements, and anticipated cash needs.

We expect to continue to distribute a substantial majority of our cash from operations to our unitholders on a quarterly basis, after, among other things, the establishment of cash reserves. To fund our growth, we may eventually need capital in excess of the amounts we may retain in our business or borrow under our Credit Facility. To the extent efforts to access capital externally are unsuccessful, our ability to grow could be significantly impaired.

Any distributions paid on our common units with respect to a quarter will be paid within 60 days after the end of such quarter.

Series B Cumulative Convertible Preferred Units

The Series B cumulative convertible preferred units were initially entitled to quarterly distributions in an amount equal to 7.0% of the face amount of the preferred units per annum (the “Distribution Rate”). The Distribution Rate adjusted on November 28, 2023, and will be readjusted every two years thereafter (each, a “Readjustment Date”). 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 then-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 November 28, 2025. We 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 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, we shall not be obligated to honor any request for such conversion if such request does not involve an underlying value of common units of at least $10.0 million based on the closing trading price of common units on the trading day immediately preceding the conversion notice date, or such lesser amount to the extent such exercise covers all of a holder's Series B cumulative convertible preferred units.

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 during biennial 90-day windows. On August 21, 2025, we entered into an agreement with the holders of its Series B cumulative convertible preferred units. Under the agreement, we agreed not to exercise our redemption option, and the holders agreed to vote their preferred units in accordance with the recommendations of our 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.

ITEM 6. RESERVED

ITEM 7. 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 consolidated financial statements and notes thereto presented elsewhere in this Annual Report. 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 I, Item 1A. Risk Factors." This discussion includes a comparison of our results of operations and liquidity and capital resources for 2025 and 2024. For the discussion of changes from 2024 to 2023 and other financial information related to 2023, refer to Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our 2024 Annual Report on Form 10-K, which was filed with the SEC on February 25, 2025.

Overview

As of December 31, 2025, our mineral and royalty interests were located in 41 states in the continental United States including all of the major onshore producing basins. These non-cost-bearing interests include ownership in approximately 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 fourth quarter, Aethon was operating three rigs on our Angelina, Nacogdoches, and San Augustine acreage in the Shelby Trough. Aethon's development program remains on track, with 6 wells spud in the second half of 2025 as part of the current program year ending June 30, 2026, an additional 8 wells expected in the first half 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. Aethon successfully turned to sales 7 gross (0.42 net) wells during the fourth quarter and has an inventory of 5 gross (0.31 net) wells from the previous program year that it expects to turn to sales during early 2026.

Our agreement with 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 expects to spud more wells than its 6-well commitment for the first program year ending December 31, 2026.

In November 2025, we entered into a 220,000 gross acre development agreement with 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 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.

For additional information about our Shelby Trough development agreements, please read Part I, Items 1. and 2. "Business and Properties—Our Assets—Shelby Trough Development Agreements".

In the Permian Basin, Coterra Energy continues to develop our acreage in Culberson County, Texas. During the third quarter, 5 gross wells (0.17 net) were turned to sales, with the remaining 34 gross (1.21 net) wells expected in the first half of 2026. A second large development of 30 gross (2.04 net) wells in the southern Delaware Basin is expected to come online in the second half of 2026 and first half of 2027.

Acquisition Activity

In the fourth quarter of 2025, we acquired $48.8 million of additional (primarily non-producing) mineral and royalty interests. From September 2023 through December 2025, we have completed $239.5 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 decreased during the year ended December 31, 2025 compared to the same period in 2024, primarily due to increased global supply and uncertainty about the outlook for global economic growth and oil demand. Supply growth from both OPEC+ and non-OPEC+ producers contributed to higher global inventories during the year, placing downward pressure on crude oil prices.

Natural gas prices increased during the year ended December 31, 2025 relative to the prior-year period. Colder-than-normal weather during the first quarter increased heating demand and reduced storage levels, while higher demand for power generation during the summer months also contributed to higher natural gas prices. In addition, continued growth in LNG export demand further strengthened market conditions. In the fourth quarter of 2025, natural gas prices rose, driven by seasonal heating demand, continued LNG export demand, and relatively tight storage levels.

Given the dynamic nature of commodity markets, we cannot reasonably estimate how long current 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:

	2025			
Benchmark Prices	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot crude oil ($/Bbl)[1]	$ 57.26	$ 63.17	$ 66.30	$ 71.87
Henry Hub spot natural gas ($/MMBtu)[1]	$ 4.00	$ 3.12	$ 3.26	$ 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:

	2025			
U.S. Rotary Rig Count[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	412	424	432	484
Natural gas	125	117	109	103
Other	9	8	6	5
Total	546	549	547	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 EIA forecasts that inventories will conclude the withdrawal season, which is the end of March 2026, at 1.8 Tcf, or 2% higher than the five-year average. The EIA expects inventories will rise to 3.8 Tcf at the end of October 2026, which would be 5% higher than the five-year average.

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

	2025			
Region[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
	(Bcf)			
East	736	832	602	284
Midwest	865	972	688	364
Mountain	264	269	228	165
Pacific	307	302	287	202
South Central	1,203	1,186	1,148	758
Total	3,375	3,561	2,953	1,773

[1] Source: EIA

Natural Gas Exports

Net natural gas exports averaged 15.0 Bcf per day during 2025, a 26% increase from the 2024 average. The EIA forecasts average exports of 16.4 Bcf per day for the start of 2026, a 9% increase from 2025 levels. The EIA forecast reflects assumptions that U.S. LNG exports will increase as new LNG export projects begin operations in 2026.

How We Evaluate Our Operations

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

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

Volumes of Oil and Natural Gas Produced

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

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

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

- *Oil*. The substantial majority of our oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. NYMEX light sweet crude oil, commonly referred to as 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 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 December 31, 2025 are detailed in Note 5 – Commodity Derivative Financial Instruments to our consolidated financial statements included elsewhere in this Annual 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 December 31, 2025, we had hedged 93% and 27% of our available oil and condensate hedge volumes and 100% and 54% of our available natural gas hedge volumes for 2026 and 2027, respectively.

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 year ended December 31, 2024 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:

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Net income	$ 299,932	$ 271,326
Adjustments to reconcile to Adjusted EBITDA:		
Depreciation, depletion, and amortization	36,887	45,196
Interest expense	8,930	3,109
Income tax expense (benefit)	(137)	509
Accretion of asset retirement obligations	1,374	1,298
Seismic data acquisition costs	17,349	2,287
Equity-based compensation	9,620	8,564
Unrealized (gain) loss on commodity derivative instruments	(36,602)	50,944
Adjusted EBITDA	337,353	383,233
Adjustments to reconcile to Distributable Cash Flow:		
Change in deferred revenue	(3)	(4)
Cash interest expense	(7,845)	(2,030)
Preferred unit distributions	(29,466)	(29,466)
Distributable Cash Flow	$ 300,039	$ 351,733

Results of Operations

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

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

	Year Ended December 31,			
	2025	2024	Variance	
	(dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	3,259	3,606	(347)	(9.6)%
Natural gas (MMcf)[1]	56,237	62,984	(6,747)	(10.7)%
Equivalents (MBoe)	12,632	14,103	(1,471)	(10.4)%
Equivalents/day (MBoe)	34.6	38.5	(3.9)	(10.1)%
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 64.24	$ 74.61	$ (10.37)	(13.9)%
Natural gas ($/Mcf)[1]	3.41	2.51	0.90	35.9 %
Equivalents ($/Boe)	$ 31.74	$ 30.27	$ 1.47	4.9 %
Revenue:				
Oil and condensate sales	$ 209,361	$ 269,061	$ (59,700)	(22.2)%
Natural gas and natural gas liquids sales[1]	191,616	157,907	33,709	21.3 %
Lease bonus and other income	21,351	12,461	8,890	71.3 %
Revenue from contracts with customers	422,328	439,429	(17,101)	(3.9)%
Gain (loss) on commodity derivative instruments	47,591	(5,730)	53,321	(930.6)%
Total revenue	$ 469,919	$ 433,699	$ 36,220	8.4 %
Operating expenses:				
Lease operating expense	$ 10,141	$ 9,705	$ 436	4.5 %
Production costs and ad valorem taxes	39,024	49,577	(10,553)	(21.3)%
Exploration expense	18,634	2,735	15,899	581.3 %
Depreciation, depletion, and amortization	36,887	45,196	(8,309)	(18.4)%
General and administrative	55,463	52,082	3,381	6.5 %
Other expense:				
Interest expense	$ 8,930	$ 3,109	$ 5,821	187.2 %

[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 year ended December 31, 2025 increased compared to the year ended December 31, 2024. The increase in total revenue from the corresponding period is due to higher natural gas and NGL sales, higher lease bonus and other income and a gain on commodity derivative instruments in 2025 compared to a loss in 2024. Lower oil revenues, resulting from reduced production and commodity prices, partially offset the overall increase in total revenue.

Oil and condensate sales. Oil and condensate sales decreased for the year ended December 31, 2025 as compared to the year ended December 31, 2024 due to lower realized commodity prices and lower production volumes. The decrease in oil and condensate production was driven by reduced production volumes in the Austin Chalk, Bakken/Three Forks, and Permian Basin play trends. Our mineral and royalty interest oil and condensate volumes accounted for 96% and 95% of total oil and condensate volumes for the years ended December 31, 2025 and 2024, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales increased for the year ended December 31, 2025 as compared to the year ended December 31, 2024 due to higher realized commodity prices partially offset by lower production volumes. The decrease in natural gas and NGL production was driven by decreased production volumes in the Austin Chalk and Haynesville/Bossier play trends. Mineral and royalty interest production accounted for 96% and 95% of our natural gas volumes for the years ended December 31, 2025 and 2024, respectively.

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 2025, we recognized $11.0 million of realized gains and $36.6 million of unrealized gains from our commodity derivatives, compared to $45.2 million of realized gains and $50.9 million of unrealized losses in 2024. The unrealized gains on our commodity contracts in 2025 were driven equally by changes in the forward commodity price curves for both natural gas and oil while the unrealized losses in 2024 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 was higher for the year ended December 31, 2025, as compared to 2024. Leasing activity in the Wolfcamp, Bakken/Three Forks, and Haynesville/Bossier plays made up the majority of lease bonus and other income for 2025, while the majority of our 2024 lease bonus and other income came from leasing activity in the Wolfcamp, Bakken/Three Forks, and Austin Chalk plays and proceeds from surface use waivers on our mineral acreage supporting solar development.

Operating Expenses

Lease operating expense. Lease operating expense includes recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense increased slightly in 2025 as compared to 2024, due to higher nonrecurring service-related expenses, including workovers.

Production costs and ad valorem taxes. Production taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the regulations of the states where the production originates, these taxes may be based on a percentage of the realized value or a fixed amount per production unit. This category also includes the costs to process and transport our production to applicable sales points. Ad valorem taxes are jurisdictional taxes levied on the value of oil and natural gas minerals and reserves. Rates, methods of calculating property values, and timing of payments vary between taxing authorities. For the year ended December 31, 2025, production and ad valorem taxes decreased as compared to the year ended December 31, 2024, primarily due to a decrease in production taxes and processing and transportation costs stemming from decreased production volumes, as well as lower ad valorem tax estimates.

Exploration expense. Exploration expense typically consists of dry-hole expenses, payments for delay rentals where we are the lessee, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense was significantly higher in 2025 as compared to 2024, primarily driven by purchases of seismic data and costs from proprietary seismic projects associated with existing and future development programs in the expanded Shelby Trough area.

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 the mid-year and year-end reserve reports, except when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization expense decreased for the year ended December 31, 2025 as compared to 2024, primarily due to lower 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 year ended December 31, 2025, general and administrative expenses slightly increased compared to 2024, primarily due to higher salaries of $1.4 million driven by increased headcount and inflation, higher software-related expenses of $1.2 million, and higher equity-based compensation of $1.2 million. The increase in equity-based compensation was due to higher costs recognized for performance-based incentive awards driven by changes in our common unit price during 2025, compared to 2024. These increases were partially offset by a $0.6 million decrease in consulting costs for internal projects.

Other Expense

Interest expense. For the year ended December 31, 2025, interest expense increased compared to 2024, primarily 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 distribution rate for the Series B cumulative convertible preferred units adjusted November 28, 2023 and will be readjusted every two years thereafter (each, a "Readjustment Date"). 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. The Distribution Rate was adjusted to 9.8% effective November 28, 2023 and remained the same at 9.8% for November 28, 2025. 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 converted 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 12 – Preferred Units" to the consolidated financial statements included elsewhere in this Annual Report 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 14 – Common Units" to the consolidated financial statements included elsewhere in this Annual Report for additional information. As of December 31, 2025, we had not made any repurchases under the program.

Cash Flows

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

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

	Year Ended December 31,		
	2025	2024	Change
		(in thousands)	
Cash flows provided by operating activities	$ 310,167	$ 389,043	$ (78,876)
Cash flows used in investing activities	(118,274)	(112,236)	(6,038)
Cash flows used in financing activities	(192,934)	(344,570)	151,636

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 provided by operating activities for 2025 decreased as compared to 2024. The decrease was primarily due to reduced oil sales due to lower realized oil prices and production, and lower amounts of cash received from the settlement of commodity derivatives. The overall decrease was partially offset by higher natural gas and NGL sales due to higher realized natural gas prices in 2025 compared to the same period in 2024.

Investing Activities. Net cash used in investing activities for 2025 slightly increased as compared to 2024. The increase was primarily due to higher additions to oil and natural gas properties leasehold costs in 2025 compared to the same period in 2024.

Financing Activities. Net cash used in financing activities for 2025 decreased as compared to 2024. The decrease was primarily due to lower distributions paid to unitholders and higher borrowings net of repayments under our Credit Facility in 2025 compared to 2024.

Development Capital Expenditures

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

Expenditures related to drilling, completion, and recompletion costs for our non-operated working interests were $0.6 million and $0.8 million during 2025 and 2024, respectively. Additionally, we spent $11.1 million and $3.4 million acquiring leases in areas around our drilling programs during 2025 and 2024, respectively.

Acquisitions

Our current commercial strategy includes the continuation of meaningful, targeted mineral and royalty acquisitions to complement our existing positions.

During 2025, we acquired mineral and royalty interests that consisted of primarily unproved oil and natural gas properties from various sellers for an aggregate of $114.5 million, including capitalized direct transaction costs. The consideration paid consisted of $107.1 million in cash that was funded from operating activities and $7.4 million in equity that was funded through the issuance of our common units based on the fair values of the common units issued on the acquisition dates. These acquisitions were considered asset acquisitions and were primarily located in East Texas, within the Haynesville expansion area.

During 2024 we acquired mineral and royalty interests that consisted of primarily unproved oil and natural gas properties from various sellers for an aggregate of $110.4 million, including capitalized direct transaction costs. The cash portion of the consideration paid of $109.4 million was funded with borrowings under our Credit Facility and funds from operating activities, and $1.0 million was funded through the issuance of our common units based on the fair values of the common units issued on the acquisition dates. These acquisitions were considered asset acquisitions and were primarily located in East Texas, within the Haynesville expansion area.

See "Note 4 – Oil and Natural Gas Properties" to the consolidated financial statements included elsewhere in this Annual Report for additional information.

Asset Exchange

We completed multiple asset exchange transactions to consolidate a concentrated acreage position in East Texas. These transactions, which are described below, involved partial dispositions of unproved property, and no gains or losses were recognized.

In March 2025, we closed on a transaction with a third-party operator whereby we acquired an oil and natural gas lease on approximately 2,900 net leasehold acres in East Texas in exchange for the assignment of approximately 900 undeveloped net mineral and royalty acres in Louisiana.

In February 2025, we closed on a transaction with a third-party operator whereby we exchanged oil and natural gas leases covering certain acreage in East Texas. We acquired approximately 2,100 net leasehold acres in exchange for approximately 3,700 net leasehold acres.

In July 2024, we closed on a transaction with a third-party operator whereby we acquired an oil and natural gas lease on approximately 8,000 net leasehold acres in East Texas in exchange for the assignment of approximately 51,000 undeveloped net mineral and royalty acres in Mississippi.

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 2024, November 2024 and April 2025 at $580.0 million. In October 2025, we amended the Credit Facility to extend the maturity date from October 31, 2027 to October 31, 2030 and remove the adjustment applied to secured overnight financing rate ("SOFR") loans. Concurrent with the Credit Facility amendment, the borrowing base under the Credit Facility was reaffirmed at $580.0 million and we elected to maintain cash commitments under the Credit Facility at $375.0 million. All existing banks in the lender syndicate elected to continue participating in the Credit Facility. No other significant terms were changed as part of the amendment. The next semi-annual redetermination is scheduled for April 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 December 31, 2025, we were in compliance with all debt covenants.

See "Note 8 – Credit Facility" to the consolidated financial statements included elsewhere in this Annual Report for additional information.

Material Cash Requirements

Our material cash requirements consist primarily of production costs and ad valorem taxes, general and administrative expenses, including payroll and benefits, office lease commitments, settlements under our commodity derivative contracts, and lease operating expenses and asset retirement obligations associated with our non-operated working interests.

We cannot provide specific timing for repayments of borrowings or associated interest under our Credit Facility, as such amounts depend on working capital requirements, commodity prices, and acquisition and divestiture activity. Similarly, the timing and amount of other obligations, including asset retirement obligations and settlements under commodity derivative contracts, cannot be forecasted with certainty. The fair value of our derivative contracts as of December 31, 2025 reflects the estimated cash settlement amount required to terminate such instruments based on forward commodity price curves as of that date. See "Note 6 – Fair Value Measurements" for additional information.

Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with GAAP. Certain of our accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used. The following discussions of critical accounting estimates, including any related discussion of contingencies, address all important accounting areas where the nature of accounting estimates or assumptions could be material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change. We have provided expanded discussion of our more significant accounting estimates below. See "Note 2 – Summary of Significant Accounting Policies" within the consolidated financial statements included elsewhere in this Annual Report for additional information.

Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, as well as reported amounts of revenues and expenses for the periods herein. Actual results could differ from those estimates.

Our consolidated financial statements are based on a number of significant estimates including oil and natural gas reserve quantities that are the basis for the calculations of depreciation, depletion, and amortization (“DD&A”) and impairment of proved oil and natural gas properties, if necessary. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. The accuracy of any reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered. Our reserve estimates are determined by an independent petroleum engineering firm. Other items subject to estimates and assumptions include the carrying amount of oil and natural gas properties, valuation of commodity derivative financial instruments, determination of revenue accruals, and the determination of the fair value of equity-based awards.

We evaluate estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. A significant decline in oil or natural gas prices could cause us to perform analyses to determine if our oil and natural gas properties are impaired. As future commodity prices cannot be predicted accurately, actual results could differ significantly from estimates.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire mineral and royalty interests and working interests in oil and natural gas properties, property acquisitions, successful exploratory wells, development costs, and support equipment and facilities are capitalized when incurred.

The costs of unproved leaseholds and non-producing mineral interests are capitalized as unproved properties pending the results of exploration and leasing efforts. As unproved properties are determined to be productive, the related costs are transferred to proved oil and natural gas properties. The costs related to exploratory wells are capitalized pending determination of whether proved commercial reserves exist. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is ongoing. Other exploratory costs, including annual delay rentals and geological and geophysical costs, are expensed when incurred.

Oil and natural gas properties are grouped in accordance with the Extractive Industries – Oil and Gas Topic of the Financial Accounting Standards Board Accounting Standards Codification. The basis for grouping is a reasonable aggregation of properties with a common geographic location, which we also refer to as a depletable unit.

As exploration and development work progresses and the reserves associated with our oil and natural gas properties become proved, capitalized costs attributed to the properties are charged as an operating expense through DD&A. DD&A of producing oil and natural gas properties is recorded based on the units-of-production method. Capitalized development costs are amortized on the basis of proved developed reserves while leasehold acquisition costs and the costs to acquire proved properties are amortized on the basis of all proved reserves, both developed and undeveloped. Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. DD&A expense related to our producing oil and natural gas properties was $35.7 million, $44.8 million, and $45.0 million for the years ended December 31, 2025, 2024, and 2023, respectively.

We evaluate impairment of producing and unproved properties whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. See "Note 6 - Fair Value Measurements" for additional information.

Upon the sale of a complete depletable unit, the book value thereof, less proceeds or salvage value, is charged to income or loss. Upon the sale or retirement of an individual well, or an aggregation of interests which make up less than a complete depletable unit, the proceeds are credited to accumulated DD&A, unless doing so would significantly alter the DD&A rate of the depletable unit, in which case a gain or loss is recorded.

We are unable to predict future commodity prices with any greater precision than the futures market. To estimate the effect lower prices would have on our reserves, we applied a 10% discount to the commodity prices used in our December 31, 2025 reserve report. Applying this discount results in an approximate 1% reduction of estimated proved reserve volumes as compared to the undiscounted pricing scenario used in our December 31, 2025 reserve report prepared by NSAI.

Accrued Revenues

We record revenue in the month production is delivered to the purchaser. As a non-operator, we have limited visibility into the timing of when new wells begin producing, and production statements may not be received for 30 to 90 days or more after production is delivered. As a result, a portion of revenue for each period is accrued and recorded in the line item Accrued revenue and accounts receivable on the consolidated balance sheets.

Accrued revenues are estimated using historical production data, adjusted for expected production declines, and projected sales prices, including applicable pricing adjustments. Differences between our estimates and the actual amounts received for oil and natural gas sales are recorded in the month that payment is received from the operator.

We review historical production, pricing assumptions, and the accuracy of prior accruals to ensure that the recorded amounts appropriately reflect revenues expected to be collected.

New and Revised Financial Accounting Standards

The effects of new accounting pronouncements are discussed in Note 2 – Summary of Significant Accounting Policies within the consolidated financial statements included elsewhere in this Annual Report.

ITEM 7A. 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 5 – Commodity Derivative Financial Instruments" and "Note 6 – Fair Value Measurements" to the consolidated financial statements included elsewhere in this Annual Report for additional information.

Based upon our open commodity derivative positions at December 31, 2025, a hypothetical $1 per barrel increase or decrease in the NYMEX WTI strip price would result in an increase or decrease of approximately $3.4 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 $7.7 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 twelve months ended December 31, 2025. Applying this discount results in an approximate 1% reduction of proved reserve volumes as compared to the undiscounted December 31, 2025 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 December 31, 2025, we had eight counterparties, all of which are rated Baa2 or better by Moody’s and are lenders under our Credit Facility.

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

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. During the year ended December 31, 2025, we had $95.8 million weighted average outstanding borrowings under our Credit Facility, bearing interest at a weighted-average interest rate of 7.03%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of $1.0 million for the year ended December 31, 2025, 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 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required here is included in this Annual Report beginning on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under 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 Annual Report. 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 December 31, 2025 to provide such reasonable assurance.

Management’s Annual Report on Internal Control over Financial Reporting

Our general partner’s management, including our general partner’s principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with GAAP.

There are inherent limitations in the effectiveness of internal control over financial reporting, including the possibility that misstatements may not be prevented or detected. Accordingly, even effective internal controls over financial reporting can provide only reasonable assurance with respect to financial statement preparation.

Under the supervision and with the participation of our general partner's principal executive officer and principal financial officer, our general partner’s management assessed the effectiveness of our internal control over financial reporting as of December 31, 2025, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, our general partner’s management believes that our internal control over financial reporting was effective as of December 31, 2025.

This Annual Report includes an attestation report of Deloitte & Touche LLP, our independent registered public accounting firm, on our internal control over financial reporting as of December 31, 2025, which is included in the Annual Report on page F-5.

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 December 31, 2025, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Except as described below, during the three months ended December 31, 2025, 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.

On December 4, 2025, Steve Putman, our Senior Vice President, General Counsel, and Secretary, adopted a trading arrangement for the sale of common units (a “Rule 10b5-1 Trading arrangement”) that is intended to satisfy the affirmative defense conditions of Securities Exchange Act Rule 10b5-1(c). Mr. Putman’s Rule 10b5-1 Trading Plan provides for the sale of approximately 90,000 common units, subject to adjustment upon future settlement of certain outstanding unit-based awards and associated distribution equivalent rights, pursuant to the terms of the plan and will terminate on the earlier of (i) December 4, 2026, (ii) the first date on which all trades set forth in the plan have been executed or (iii) such date as the plan is otherwise terminated according to its terms.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Information required by this item and not otherwise provided below is incorporated by reference to the material appearing in our Proxy Statement for the 2026 Annual Meeting of Limited Partners ("2026 Proxy Statement"), which will be filed with the SEC not later than 120 days after December 31, 2025.

The following table shows information for the executive officers and directors of the General Partner as of February 24, 2026. Executive officers serve at the discretion of the Board. Directors hold office until their successors are duly elected and qualified.

Name	Age	Position With The General Partner
Thomas L. Carter, Jr.	74	Executive Chairman of the Board of Directors
Fowler T. Carter	46	Co-Chief Executive Officer and President
H. Taylor DeWalch	36	Co-Chief Executive Officer and President
Chris R. Bonner	36	Senior Vice President, Chief Financial Officer, and Treasurer
L. Steve Putman	50	Senior Vice President, General Counsel, and Secretary
Carin M. Barth	63	Director
D. Mark DeWalch	64	Director
Anne L. Hamman	65	Director
Jerry V. Kyle, Jr.	65	Director
Michael C. Linn	74	Director
A.J. Longmaid	48	Director
William E. Randall	59	Director
Alexander D. Stuart	75	Director
James W. Whitehead	50	Director

We have a Code of Business Conduct and Ethics that applies to our directors, officers, and employees as well as a Financial Code of Ethics that applies to our Co-Chief Executive Officers, Chief Financial Officer, Principal Accounting Officer, and the other senior financial officers, each as required by SEC and NYSE rules. Each of the foregoing is available on our website at www.blackstoneminerals.com in the "Corporate Governance" section. We will provide copies, free of charge, of any of the foregoing upon receipt of a written request to Black Stone Minerals, L.P., 1001 Fannin Street, Suite 2020, Houston, Texas 77002, Attn: Investor Relations. We intend to disclose amendments to and waivers, if any, from our Code of Business Conduct and Ethics and Financial Code of Ethics, as required, on our website, www.blackstoneminerals.com, promptly following the date of any such amendment or waiver.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to the 2026 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2025.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Information required by this item is incorporated by reference to the 2026 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2025.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to the 2026 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2025.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Our independent registered public accounting firm is Deloitte & Touche LLP, Houston TX, Auditor Firm ID: 34.

Information required by this item is incorporated by reference to the 2026 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2025.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

Our Consolidated Financial Statements are included under Part II, Item 8 of this Annual Report. For a listing of these statements and accompanying notes, please read "Index to Financial Statements" on page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

The following documents are filed as a part of this Annual Report or incorporated by reference:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.1 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.2 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.3	First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated May 6, 2015, by and among Black Stone Minerals GP, L.L.C. and Black Stone Minerals Company, L.P., (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on May 6, 2015 (SEC File No. 001-37362)).
3.4	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of April 15, 2016 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 19, 2016 (SEC File No. 001-37362)).
3.5	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of November 28, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)).
3.6	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of December 11, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on December 12, 2017 (SEC File No. 001-37362)).
3.7	Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of the Black Stone Minerals, L.P., dated as of April 22, 2020 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 24, 2020 (SEC File No. 001-37362)).
4.1	Description of Securities (incorporated herein by reference to Exhibit 4.1 of Black Stone Minerals, L.P.'s Annual Report on Form 10-K filed on February 25, 2020 (SEC File No. 001-37362)).
4.2	Registration Rights Agreement, dated as of November 28, 2017, by and between Black Stone Minerals, L.P. and Minerals Royalties One, L.L.C. (incorporated herein by reference to Exhibit 4.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)).
10.1^	Black Stone Minerals, L.P. Long-Term Incentive Plan, dated May 6, 2015, by Black Stone Minerals GP, L.L.C. (incorporated herein by reference to Exhibit 10.1 Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on May 6, 2015 (SEC File No. 001-37362)).
10.2^	Black Stone Minerals, L.P. 2025 Long-Term Incentive Plan, dated as of April 16, 2025, by Black Stone Minerals GP, L.L.C. (incorporated herein by reference to Exhibit 10.1 Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on June 18, 2025 (SEC File No. 001-37362)).

10.3	Fifth Amended and Restated Credit Agreement, among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P., as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, Bank of America, N.A. and PNC Capital Markets LLC, as Co-Syndication Agents, Zions Bancorporation, N.A., DBA Amegy Bank, as Documentation Agent, and the lenders signatory thereto, dated as of October 31, 2022 (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on November 1, 2022 (SEC File No. 001-37362)).
10.4^	Form of Non-Employee Director Unit Grant Notice and Award Agreement under the Black Stone Minerals, L.P. 2025 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on November 4, 2025 (SEC File No. 001-37362)).
10.5^	Form of Severance Agreement for Thomas L. Carter, Jr. (incorporated herein by reference to Exhibit 10.12 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on April 13, 2015 (SEC File No. 333-202875)).
10.6^	Form of Severance Agreement for Senior Vice Presidents (incorporated herein by reference to Exhibit 10.11 to Black Stone Minerals, L.P.'s Annual Report on Form 10-K filed on February 20, 2024 (SEC File No. 001-37362)).
10.7^	2023 Form of LTI Award Grant Notice and LTI Award Agreement (Leadership Performance Units) under the Black Stone Minerals, L.P. Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.12 to Black Stone Minerals, L.P.'s Annual Report on Form 10-K filed on February 23, 2023 (SEC File No. 001-37362)).
10.8^	2023 Form of LTI Award Grant Notice and LTI Award Agreement (Leadership Restricted Units) under the Black Stone Minerals, L.P. Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.13 to Black Stone Minerals, L.P.'s Annual Report on Form 10-K filed on February 23, 2023 (SEC File No. 001-37362)).
10.9^	Form of STI Award Letter (Leadership) under the Black Stone Minerals, L.P. 2025 Long-Term Incentive Plan. (incorporated herein by reference to Exhibit 10.6 to Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on November 4, 2025 (SEC File No. 001-37362))
10.10^	2024 Form of LTI Award Grant Notice and LTI Award Agreement (Leadership Restricted Units) under the Black Stone Minerals, L.P. Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on May 7, 2024 (SEC File No. 001-37362)).
10.11^	2024 Form of LTI Award Grant Notice and LTI Award Agreement (Leadership Performance Units) under the Black Stone Minerals, L.P. Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on May 7, 2024 (SEC File No. 001-37362)).
10.12 ^	2025 Form of LTI Award Grant Notice and LTI Award Agreement (Leadership Restricted Units) under the Black Stone Minerals, L.P. 2025 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.5 to Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on November 4, 2025 (SEC File No. 001-37362)).
10.13^	2025 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 10.4 to Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on November 4, 2025 (SEC File No. 001-37362)).
10.14^*	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.
10.15^	Separation Agreement and General Release of Claims, dated as of June 29, 2025, by and among Carrie Clark, Black Stone Natural Resources Management Company, and Black Stone Minerals GP, L.L.C. (incorporated herein by reference to Exhibit 10.1 Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on June 30, 2025 (SEC File No. 001-37362)).
10.16	Series B Preferred Unit Purchase Agreement, dated as of November 22, 2017, by and between Black Stone Minerals L.P. and Mineral Royalties One, L.L.C. (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)).
10.17	Unitholder Agreement, dated as of August 22, 2025, by and between Black Stone Minerals, L.P. and AP Basileia SPV, LLC. (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P. Current Report on Form 8-K filed on August 22, 2025 (SEC File No. 001-37362)).

10.18	First Amendment to Fifth Amended and Restated Credit Agreement, among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P., as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent, dated as of October 31, 2025 (incorporated herein by reference to Exhibit 10.2 to Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on November 4, 2025 (SEC File No. 001-37362)).
19.1	Black Stone Minerals, L.P. Insider Trading Policy (incorporated herein by reference to Exhibit 19.1 to Black Stone Minerals, L.P.'s Annual Report on Form 10-K filed on February 25, 2025 (SEC File No. 001-37362)).
21.1*	List of Subsidiaries of Black Stone Minerals, L.P.
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Ernst & Young LLP
23.3*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Co-Chief Executive Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Co-Chief Executive Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3*	Certification of Chief Financial Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of 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
97.1	Black Stone Minerals, L.P. Incentive-Based Compensation Recoupment Policy, adopted as of October 18, 2023 (incorporated herein by reference to Exhibit 97.1 to Black Stone Minerals, L.P.'s Annual Report on Form 10-K filed on February 20, 2024 (SEC File No. 001-37362)).
99.1*	Report of Netherland, Sewell & Associates, Inc.
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 Taxonomy Schema Document.
101.CAL*	Inline XBRL Taxonomy Calculation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Definition Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Presentation Linkbase Document.
104*	Cover Page Interactive Data File - the cover page iXBRL tags are embedded within the Inline XBRL document.

* Filed 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: February 24, 2026

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

Date: February 24, 2026

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Fowler T. Carter	Co-Chief Executive Officer and President	February 24, 2026
Fowler T. Carter	(Principal Executive Officer)	
/s/ H. Taylor DeWalch	Co-Chief Executive Officer and President	February 24, 2026
H. Taylor DeWalch	(Principal Executive Officer)	
/s/ Chris R. Bonner	Senior Vice President, Chief Financial Officer, and Treasurer	February 24, 2026
Chris R. Bonner	(Principal Financial Officer)	
/s/ Erin L. Phillips	Controller	February 24, 2026
Erin L. Phillips	(Principal Accounting Officer)	
/s/ Thomas L. Carter, Jr.	Executive Chairman	February 24, 2026
Thomas L. Carter, Jr.		
/s/ Carin M. Barth	Director	February 24, 2026
Carin M. Barth		
/s/ D. Mark DeWalch	Director	February 24, 2026
D. Mark DeWalch		
/s/ Anne L. Hamman	Director	February 24, 2026
Anne L. Hamman		
/s/ Jerry V. Kyle, Jr.	Director	February 24, 2026
Jerry V. Kyle, Jr.		
/s/ Michael C. Linn	Director	February 24, 2026
Michael C. Linn		
/s/ A.J. Longmaid	Director	February 24, 2026
A.J. Longmaid		
/s/ William E. Randall	Director	February 24, 2026
William E. Randall		
/s/ Alexander D. Stuart	Director	February 24, 2026
Alexander D. Stuart		
/s/ James W. Whitehead	Director	February 24, 2026
James W. Whitehead		

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
BLACK STONE MINERALS, L.P.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Black Stone Minerals GP, L.L.C. and the unitholders of Black Stone Minerals, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Black Stone Minerals, L.P. and subsidiaries (the "Partnership") as of December 31, 2025, the related consolidated statements of operations, equity, and cash flows, for the year ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2025, and the results of its operations and its cash flows for the year ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2026, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Proved Oil and Gas Properties and Depletion – Estimated Proved Reserves —Refer to Note 2 to the Financial Statements

Critical Audit Matter Description

The Partnership’s capitalized costs of proved oil and gas properties are depleted using the units of production method based on estimated proved reserves. In order to develop the Partnership’s estimated proved reserve volumes, consisting of crude oil and natural gas quantities, management and an independent petroleum engineering firm engaged by the Partnership use significant estimates and assumptions. Changes in these estimates and assumptions could materially affect the estimated quantities of the Partnership’s reserves and therefore calculation of depletion expense.

Given the significant estimates and assumptions made by management and the independent petroleum engineering firm, performing audit procedures to evaluate the Partnership’s estimated proved reserve quantities required a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to proved reserve quantities included the following, among others:

- We tested the design, implementation, and operating effectiveness of controls related to the Partnership's estimation of proved reserves.
- We evaluated the Partnership's estimated proved reserves by:
  - Comparing the Partnership's estimated future production from reserves to historical production volumes.
  - Assessing the reasonableness of the production volume decline curve estimates by comparing to historical decline curves.
  - Assessing the pricing and differential inputs used to estimate proved reserves.
  - Reviewing internal communications to management and the Board of Directors.
  - Reviewing the forecasts of future production in relation to information included in the Partnership's press releases, investor presentations and relevant internal data.
- We evaluated the experience, qualifications and objectivity of management's expert, an independent petroleum engineering firm, including the methodologies used to independently engineer proved reserve quantities.

/s/ Deloitte & Touche LLP

Houston, Texas
February 24, 2026

We have served as the Partnership's auditor since 2025.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders and the Board of Directors of Black Stone Minerals, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Black Stone Minerals, L.P. and subsidiaries (the Partnership) as of December 31, 2024, the related consolidated statements of operations, equity and cash flows for each of the two years in the period ended December 31, 2024, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2024, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2024, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We served as the Partnership's auditor from 2016 to 2024.
Houston, Texas
February 25, 2025

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Black Stone Minerals GP, L.L.C. and the unitholders of Black Stone Minerals, L.P.

Opinion on Internal Control Over Financial Reporting

We have audited the internal control over financial reporting of Black Stone Minerals, L.P. and subsidiaries (the "Partnership") as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2025, of the Partnership and our report dated February 24, 2026, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Houston, Texas
February 24, 2026

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

	As of December 31,	
	2025	**2024**
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,478	$ 2,519
Accrued revenue and accounts receivable	65,572	71,093
Commodity derivative assets, net	18,864	1,824
Prepaid expenses and other current assets	9,722	3,108
TOTAL CURRENT ASSETS	95,636	78,544
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $1,063,709 and $973,028 at December 31, 2025 and 2024, respectively	3,079,340	3,105,457
Accumulated depreciation, depletion, amortization, and impairment	(1,855,332)	(1,973,460)
Oil and natural gas properties, net	1,224,008	1,131,997
Other property and equipment, net of accumulated depreciation of $15,768 and $14,511 at December 31, 2025 and 2024, respectively	1,126	2,044
NET PROPERTY AND EQUIPMENT	1,225,134	1,134,041
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	14,784	6,321
TOTAL ASSETS	$ 1,335,554	$ 1,218,906
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 2,823	$ 5,946
Accrued liabilities	19,388	17,242
Commodity derivative liabilities, net	—	3,852
Other current liabilities	2,412	3,383
TOTAL CURRENT LIABILITIES	24,623	30,423
LONG-TERM LIABILITIES		
Credit facility	154,000	25,000
Accrued incentive compensation	1,011	1,234
Commodity derivative liabilities, net	—	11,581
Asset retirement obligations	22,716	19,286
Other long-term liabilities	4,748	1,943
TOTAL LIABILITIES	207,098	89,467
COMMITMENTS AND CONTINGENCIES (Note 11)		
MEZZANINE EQUITY		
Partners' equity — Series B cumulative convertible preferred units, 14,711 and 14,711 units outstanding at December 31, 2025 and 2024, respectively	300,478	300,478
EQUITY		
Partners' equity — general partner interest	—	—
Partners' equity — common units, 211,873 and 210,695 units outstanding at December 31, 2025 and 2024, respectively	827,978	828,961
TOTAL EQUITY	827,978	828,961
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,335,554	$ 1,218,906

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

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

	Year Ended December 31,		
	2025	**2024**	**2023**
REVENUE			
Oil and condensate sales	$ 209,361	$ 269,061	$ 288,296
Natural gas and natural gas liquids sales	191,616	157,907	200,297
Lease bonus and other income	21,351	12,461	12,506
Revenue from contracts with customers	422,328	439,429	501,099
Gain (loss) on commodity derivative instruments, net	47,591	(5,730)	91,117
TOTAL REVENUE	469,919	433,699	592,216
OPERATING (INCOME) EXPENSE			
Lease operating expense	10,141	9,705	11,386
Production costs and ad valorem taxes	39,024	49,577	56,979
Exploration expense	18,634	2,735	2,148
Depreciation, depletion, and amortization	36,887	45,196	45,683
General and administrative	55,463	52,082	51,455
Accretion of asset retirement obligations	1,374	1,298	1,042
Gain on sale of assets, net	—	—	(73)
TOTAL OPERATING EXPENSE	161,523	160,593	168,620
INCOME FROM OPERATIONS	308,396	273,106	423,596
OTHER INCOME (EXPENSE)			
Interest and investment income	237	1,666	1,867
Interest expense	(8,930)	(3,109)	(2,754)
Other income (expense), net	229	(337)	(160)
TOTAL OTHER EXPENSE	(8,464)	(1,780)	(1,047)
NET INCOME	299,932	271,326	422,549
Distributions on Series B cumulative convertible preferred units	(29,466)	(29,466)	(21,776)
NET INCOME ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 270,466	$ 241,860	$ 400,773
ALLOCATION OF NET INCOME:			
General partner interest	$ —	$ —	$ —
Common units	270,466	241,860	400,773
	$ 270,466	$ 241,860	$ 400,773
NET INCOME ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:			
Per common unit (basic)	$ 1.28	$ 1.15	$ 1.91
Per common unit (diluted)	$ 1.28	$ 1.15	$ 1.88
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:			
Weighted average common units outstanding (basic)	211,667	210,684	209,970
Weighted average common units outstanding (diluted)	211,729	210,780	225,105

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

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

	Common units	Partners' equity
BALANCE AT DECEMBER 31, 2022	209,407	$ 911,451
Repurchases of common units	(358)	(5,496)
Restricted units granted, net of forfeitures	942	—
Equity-based compensation	—	12,525
Distributions to common unitholders ($1.90 per unit)	—	(398,824)
Charges to partners' equity for accrued distribution equivalent rights	—	(2,221)
Distributions on Series B cumulative convertible preferred units ($1.48 per unit)	—	(21,776)
Net income	—	422,549
BALANCE AT DECEMBER 31, 2023	209,991	918,208
Repurchases of common units	(291)	(4,449)
Issuance of common units for acquisition of oil and natural gas properties	64	1,039
Restricted units granted, net of forfeitures	931	—
Equity-based compensation	—	10,441
Distributions to common unitholders ($1.60 per unit)	—	(336,931)
Charges to partners' equity for accrued distribution equivalent rights	—	(1,207)
Distributions on Series B cumulative convertible preferred units ($2.00 per unit)	—	(29,466)
Net income	—	271,326
BALANCE AT DECEMBER 31, 2024	210,695	828,961
Repurchases of common units	(259)	(3,777)
Issuance of common units for acquisition of oil and natural gas properties	509	7,417
Restricted units granted, net of forfeitures	928	—
Equity-based compensation	—	11,540
Distributions to common unitholders ($1.35 per unit)	—	(285,654)
Charges to partners' equity for accrued distribution equivalent rights	—	(975)
Distributions on Series B cumulative convertible preferred units ($2.00 per unit)	—	(29,466)
Net income	—	299,932
BALANCE AT DECEMBER 31, 2025	211,873	$ 827,978

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

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

	Year Ended December 31,		
	2025	**2024**	**2023**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 299,932	$ 271,326	$ 422,549
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	36,887	45,196	45,683
Accretion of asset retirement obligations	1,374	1,298	1,042
Amortization of deferred charges	1,085	1,079	1,039
(Gain) loss on commodity derivative instruments	(47,591)	5,730	(91,117)
Net cash (paid) received on settlement of commodity derivative instruments	10,989	45,214	82,723
Equity-based compensation	9,620	8,564	10,829
Gain on sale of assets, net	—	—	(73)
Changes in operating assets and liabilities:			
Accrued revenue and accounts receivable	5,545	11,244	53,053
Prepaid expenses and other current assets	(6,614)	(789)	(414)
Accounts payable, accrued liabilities, and other	(286)	1,042	(3,827)
Settlement of asset retirement obligations	(774)	(861)	(236)
NET CASH PROVIDED BY OPERATING ACTIVITIES	310,167	389,043	521,251
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisitions of oil and natural gas properties	(107,052)	(109,393)	(14,605)
Additions to oil and natural gas properties	(640)	(790)	(4,213)
Additions to oil and natural gas properties leasehold costs	(11,118)	(3,423)	(545)
Purchases of other property and equipment	(298)	(1,425)	(450)
Proceeds from the sale of oil and natural gas properties	834	2,795	73
NET CASH USED IN INVESTING ACTIVITIES	(118,274)	(112,236)	(19,740)
CASH FLOWS FROM FINANCING ACTIVITIES			
Distributions to common unitholders	(285,654)	(336,931)	(398,824)
Distributions to Series B cumulative convertible preferred unitholders	(29,466)	(28,126)	(21,000)
Repurchases of common units	(3,777)	(4,449)	(5,496)
Borrowings under credit facility	373,000	97,000	64,000
Repayments under credit facility	(244,000)	(72,000)	(74,000)
Debt issuance costs and other	(3,037)	(64)	(216)
NET CASH (USED IN) PROVIDED BY FINANCING ACTIVITIES	(192,934)	(344,570)	(435,536)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(1,041)	(67,763)	65,975
Cash and cash equivalents — beginning of the year	2,519	70,282	4,307
Cash and cash equivalents — end of the year	$ 1,478	$ 2,519	$ 70,282
SUPPLEMENTAL DISCLOSURE			
Interest paid	$ 7,383	$ 1,961	$ 1,736
Common units issued for property acquisitions	$ 7,417	$ 1,039	$ —

The accompanying notes to consolidated financial statements are an integral part of these 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 audited consolidated financial statements of the Partnership have been prepared in accordance with generally accepted accounting principles (“GAAP”) in the U.S. and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC").

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 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 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 our 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 allocates resources and assesses 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, depletion, depreciation, 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.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, as well as reported amounts of revenues and expenses for the periods herein. Actual results could differ from those estimates.

The Partnership's consolidated financial statements are based on a number of significant estimates including oil and natural gas reserve quantities that are the basis for the calculations of depreciation, depletion, and amortization ("DD&A") and impairment of proved oil and natural gas properties, if necessary. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. The accuracy of any reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered. The Partnership's reserve estimates are determined by an independent petroleum engineering firm. Other items subject to estimates and assumptions include the carrying amount of oil and natural gas properties, valuation of commodity derivative financial instruments, determination of revenue accruals, and the determination of the fair value of equity-based awards.

The Partnership evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. A significant decline in oil or natural gas prices could cause the Partnership to perform analyses to determine if its oil and natural gas properties are impaired. As future commodity prices cannot be predicted accurately, actual results could differ significantly from estimates.

Cash and Cash Equivalents

The Partnership considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accrued Revenue and Accounts Receivable

The Partnership’s accrued revenue and accounts receivable balance results primarily from operators’ sales of oil and natural gas to purchasers. Accrued revenue and accounts receivable are recorded at the contractual amounts and do not bear interest. Any concentration of operators may impact the Partnership’s overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions impacting the oil and natural gas industry.

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

	December 31,	
	2025	2024
	(in thousands)	
Accrued revenue	$ 62,679	$ 67,047
Accounts receivable	2,893	4,046
Total accrued revenue and accounts receivable	$ 65,572	$ 71,093

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 gas commodity derivative financial instruments. From time to time, such instruments may include variable-to-fixed-price swaps, costless collars, fixed-price contracts, and other contractual arrangements. The Partnership does not enter into derivative instruments for speculative purposes.

Derivative instruments are recognized at fair value. If a right of offset exists under master netting arrangements and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the consolidated balance sheets. The Partnership does not specifically designate derivative instruments as cash flow hedges, even though they reduce its exposure to changes in oil and natural gas prices; therefore, gains and losses arising from changes in the fair value of derivative instruments are recognized on a net basis in the accompanying consolidated statements of operations within Gain (loss) on commodity derivative instruments. Realized and unrealized gains on commodity derivative instruments are recorded within cash flows from operating activities in the accompanying consolidated statements of cash flows.

Concentration of Credit Risk

Financial instruments that potentially subject the Partnership to credit risk consist principally of cash and cash equivalents, accounts receivable, and commodity derivative financial instruments.

The Partnership maintains cash and cash equivalent balances with major financial institutions. At times, those balances exceed federally insured limits; however, no losses have been incurred.

The Partnership’s customer base is made up of its lessees, which consist of integrated oil and gas companies to independent producers and operators. The Partnership’s credit risk may also include the purchasers of oil and natural gas produced from the Partnership’s properties. The Partnership attempts to limit the amount of credit exposure to any one company through procedures that include credit approvals, credit limits and terms, and prepayments. The Partnership believes the credit quality of its operator base is high and has not experienced significant write-offs in its accounts receivable balances. See "Note 7 – Significant Operators" for additional information.

Commodity derivative financial instruments may expose the Partnership to credit risk; however, the Partnership monitors the creditworthiness of its counterparties. See "Note 5 – Commodity Derivative Financial Instruments" for additional information.

Oil and Natural Gas Properties

The Partnership follows the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire mineral and royalty interests and working interests in oil and natural gas properties, property acquisitions, successful exploratory wells, development costs, and support equipment and facilities are capitalized when incurred.

The costs of unproved leaseholds and non-producing mineral interests are capitalized as unproved properties pending the results of exploration and leasing efforts. As unproved properties are determined to be productive, the related costs are transferred to proved oil and natural gas properties. The costs related to exploratory wells are capitalized pending determination of whether proved commercial reserves exist. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is ongoing. Other exploratory costs, including annual delay rentals and geological and geophysical costs, are expensed when incurred.

Oil and natural gas properties are grouped in accordance with the Extractive Industries – Oil and Gas Topic of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC"). The basis for grouping is a reasonable aggregation of properties with a common geographic location, which the Partnership also refers to as a depletable unit.

As exploration and development work progresses and the reserves associated with the Partnership's oil and natural gas properties become proved, capitalized costs attributed to the proved properties are charged as an operating expense through DD&A. DD&A of producing oil and natural gas properties is recorded based on the units-of-production method. Capitalized development costs are amortized on the basis of proved developed reserves while leasehold acquisition costs and the costs to acquire proved properties are amortized on the basis of all proved reserves, both developed and undeveloped. Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. DD&A expense related to the Partnership's producing oil and natural gas properties was $35.7 million, $44.8 million, and $45.0 million for the years ended December 31, 2025, 2024, and 2023, respectively.

The Partnership evaluates impairment of producing and unproved properties whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. See "Note 6 - Fair Value Measurements" for additional information.

Upon the sale of a complete depletable unit, the book value thereof, less proceeds or salvage value, is charged to income or loss. Upon the sale or retirement of an individual well, or an aggregation of interests which make up less than a complete depletable unit, the proceeds are credited to accumulated DD&A, unless doing so would significantly alter the DD&A rate of the depletable unit, in which case a gain or loss would be recorded.

Other Property and Equipment

Other property and equipment includes furniture, fixtures, office equipment, leasehold improvements, and computer software and is stated at historical cost. Depreciation and amortization are calculated using the straight-line method over expected useful lives ranging from 3 years to 7 years. Depreciation and amortization expense totaled $1.2 million, $0.4 million, and $0.7 million for the years ended December 31, 2025, 2024, and 2023, respectively.

Repairs and Maintenance

The cost of normal maintenance and repairs is charged to expense as incurred. Material expenditures that increase the life of an asset are capitalized and depreciated over the shorter of the estimated remaining useful life of the asset or the term of the lease, if applicable.

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31,	
	2025	2024
	(in thousands)	
Accrued liabilities:		
Accrued incentive compensation	$ 7,824	$ 8,356
Accrued general and administrative	847	954
Accrued property taxes	6,029	6,498
Accrued lease operating expenses	1,985	713
Accrued seismic costs	1,500	—
Accrued other	1,203	721
Total accrued liabilities	$ 19,388	$ 17,242

Debt Issuance Costs

Debt issuance costs consist of costs directly associated with obtaining credit with financial institutions. These costs are capitalized and are amortized on a straight-line basis over the life of the credit agreement, which approximates the effective-interest method. Any unamortized debt issuance costs are expensed in the year when the associated debt instrument is terminated. Amortization expense for debt issuance costs was $1.1 million, $1.1 million, and $1.0 million for the years ended December 31, 2025, 2024, and 2023, respectively, and is included in interest expense in the consolidated statements of operations.

Asset Retirement Obligations

Fair values of legal obligations to retire and remove long-lived assets are recorded when the obligation is incurred and becomes determinable. When the liability is initially recorded, the Partnership capitalizes this cost by increasing the carrying amount of the related property. Over time, the liability is accreted for the change in its present value, and the capitalized cost in oil and natural gas properties is depleted based on units-of-production consistent with the related asset.

Leases

The Partnership determines if an arrangement is a lease at inception by considering whether (1) explicitly or implicitly identified assets have been deployed in the agreement and (2) the Partnership obtains substantially all of the economic benefits from the use of that underlying asset and directs how and for what purpose the asset is used during the term of the agreement. Operating leases are included in Deferred charges and other long-term assets, Other current liabilities, and Other long-term liabilities in the consolidated balance sheets. As of December 31, 2025 and 2024, none of the Partnership’s leases were classified as financing leases.

Right-of-use ("ROU") assets represent the Partnership’s right to use an underlying asset for the lease term and operating lease liabilities represent the Partnership’s obligation to make lease payments arising from the lease. ROU assets are recognized at commencement date and consist of the present value of remaining lease payments over the lease term, initial direct costs, prepaid lease payments less any lease incentives. Operating lease liabilities are recognized at commencement date based on the present value of remaining lease payments over the lease term. The Partnership uses the implicit rate, when readily determinable, or its incremental borrowing rate based on the information available at commencement date to determine the present value of lease payments.

The lease terms may include periods covered by options to extend the lease when it is reasonably certain that the Partnership will exercise that option and periods covered by options to terminate the lease when it is not reasonably certain that the Partnership will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term. The Partnership made an accounting policy election to not recognize leases with terms of less than twelve months on the consolidated balance sheets and recognize those lease payments in the consolidated statements of operations on a straight-line basis over the lease term. In the event that the Partnership’s assumptions and expectations change, it may have to revise its ROU assets and operating lease liabilities.

Revenues from Contracts with Customers

ASC 606, *Revenue from Contracts with Customers*, requires the Partnership to identify the distinct promised goods and services within a contract which represent separate performance obligations and determine the transaction price to allocate to the performance obligations identified.

Oil and natural gas sales

Sales of oil and natural gas are recognized at the point control of the product is transferred to the customer and collectability of the sales price is reasonably assured. Oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. The price the Partnership receives for natural gas is tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality and heat content of natural gas, and prevailing supply and demand conditions, so that the price of natural gas fluctuates to remain competitive with other available natural gas supplies. As each unit of product represents a separate performance obligation and the consideration is variable as it relates to oil and natural gas prices, the Partnership recognizes revenue from oil and natural gas sales using the practical expedient for variable consideration in ASC 606.

The Partnership records revenue in the month production is delivered to the purchaser. As a non-operator, the Partnership has limited visibility into the timing of when new wells start producing and production statements may not be received for 30 to 90 days or more after the date production is delivered. As a result, the Partnership is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The expected sales volumes and prices for these properties are estimated and recorded within the Accrued revenue and accounts receivable line item in the accompanying consolidated balance sheets. The difference between the Partnership's estimates and the actual amounts received for oil and natural gas sales is recorded in the month that payment is received from the third party.

Lease bonus and other income

The Partnership also earns revenue from lease bonuses and delay rentals. The Partnership generates lease bonus revenue by leasing its mineral interests to exploration and production companies. A lease agreement represents the Partnership's contract with a customer and generally transfers the rights to any oil or natural gas discovered, grants the Partnership a right to a specified royalty interest, and requires that drilling and completion operations commence within a specified time period. Control is transferred to the lessee and the Partnership has satisfied its performance obligation when the lease agreement is executed, such that revenue is recognized when the lease bonus payment is received. At the time the Partnership executes the lease agreement, the Partnership expects to receive the lease bonus payment within a reasonable time, though in no case more than one year, such that the Partnership has not adjusted the expected amount of consideration for the effects of any significant financing component per the practical expedient in ASC 606. The Partnership also recognizes revenue from delay rentals to the extent drilling has not started within the specified period, payment has been received, and the Partnership has no further obligation to refund the payment.

Allocation of transaction price to remaining performance obligations

<u>Oil and natural gas sales</u>

The Partnership has utilized the practical expedient in ASC 606 which states the Partnership is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. As the Partnership has determined that each unit of product generally represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Lease bonus and other income

Given that the Partnership does not recognize lease bonus or other income until a lease agreement has been executed, at which point its performance obligation has been satisfied, and payment is received, the Partnership does not record revenue for unsatisfied or partially unsatisfied performance obligations as of the end of the reporting period.

Income Taxes

The Partnership is organized as a pass-through entity for income tax purposes. As a result, the Partnership's unitholders are responsible for federal and state income taxes attributable to their share of the Partnership's taxable income. The Partnership is subject to other state-based taxes; however, those taxes are not material. Limited partnerships that receive at least 90% of their gross income from designated passive sources, including royalties from mineral properties and other non-operated mineral interest income, and do not receive more than 10% of their income from operating an active trade or business, are classified as "passive entities" and are generally exempt from the Texas margin tax. The Partnership believes that it meets the requirements for being considered a "passive entity" for Texas margin tax purposes. As a result, each unitholder that is considered a taxable entity under the Texas margin tax would generally be required to include its portion of the Partnership's revenues in its own Texas margin tax computation. The Texas Administrative Code provides such income is sourced according to the principal place of business of the Partnership, which would be the state of Texas.

Fair Value of Financial Instruments

The carrying values of the Partnership's current financial instruments, which include cash and cash equivalents, accounts receivable, and accounts payable approximate their fair value at December 31, 2025 and 2024 due to the short-term maturity of these instruments. See "Note 6 – Fair Value Measurements" for additional information.

Incentive Compensation

Incentive compensation includes both liability awards and equity-based awards. The Partnership recognizes compensation expense associated with its incentive compensation awards using either straight-line or accelerated attribution over the requisite service period (generally the vesting period of the awards) depending on the given terms of the award, based on their grant date fair values. Liability awards are awards that are expected to be settled in cash or an unknown number of common units on their vesting dates. Liability awards are recorded as accrued liabilities based on the vested portion of the estimated fair value of the awards as of the grant date, which is subject to revision based on the impact of certain performance conditions associated with the incentive plans.

Incentive compensation expense is charged to the General and administrative line item on the consolidated statements of operations. See "Note 9 – Incentive Compensation" for additional information.

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 — ASSET RETIREMENT OBLIGATIONS

The asset retirement obligation ("ARO") liability reflects the present value of estimated costs of dismantlement, removal, site reclamation, and similar activities associated with the Partnership's working interest oil and natural gas properties. The current portion of our ARO is included in the line item Other current liabilities on the consolidated balance sheet, while the noncurrent portion is separately presented as Asset retirement obligations within long-term liabilities. The Partnership utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Partnership estimates the ultimate productive life of the properties, a credit-adjusted risk-free rate, and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance.

The following table describes changes to the Partnership's ARO liability for the periods presented:

	For the year ended December 31,	
	2025	2024
	(in thousands)	
Beginning asset retirement obligations	$ 21,318	$ 20,267
Liabilities incurred	30	46
Liabilities settled	(774)	(713)
Accretion expense	1,374	1,298
Revisions in estimated costs	2,330	953
Dispositions	(13)	(533)
Ending asset retirement obligations	$ 24,265	$ 21,318
Current asset retirement obligations	$ 1,549	$ 2,032
Noncurrent asset retirement obligations	$ 22,716	$ 19,286

NOTE 4 — OIL AND NATURAL GAS PROPERTIES

Acquisitions

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 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 values of the common units issued on the acquisition dates.

During the year ended December 31, 2024, 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 $110.4 million, including capitalized direct transaction costs, and were considered asset acquisitions. The cash portion of the consideration paid of $109.4 million was funded with our borrowings under our Credit Facility and funds from operating activities, and $1.0 million in equity that was funded through the issuance of common units of the Partnership based on the fair values of the common units issued on the acquisition dates.

During the year ended December 31, 2023, the Partnership acquired mineral and royalty interests that were considered asset acquisitions from various sellers for cash consideration of $14.6 million, including capitalized direct transaction costs. The acquisitions were funded with cash from operating activities and were primarily located in East Texas.

Asset Exchange

The Partnership completed multiple asset exchange transactions to consolidate a concentrated acreage position in East Texas. These transactions, which are described below, involved partial dispositions of unproved property, and no gains or losses were recognized.

In March 2025, the Partnership closed on a transaction with a third-party operator whereby the Partnership acquired an oil and natural gas lease on approximately 2,900 net leasehold acres in East Texas in exchange for the assignment of approximately 900 undeveloped net mineral and royalty acres in Louisiana.

In February 2025, the Partnership closed on a transaction with a third-party operator whereby the Partnership exchanged oil and natural gas leases covering certain acreage in East Texas. The Partnership acquired approximately 2,100 net leasehold acres in exchange for approximately 3,700 net leasehold acres.

In July 2024, the Partnership closed on a transaction with a third-party operator whereby the Partnership acquired an oil and natural gas lease on approximately 8,000 net leasehold acres in East Texas in exchange for the assignment of approximately 51,000 undeveloped net mineral and royalty acres in Mississippi.

Farmout Agreements

The Partnership previously entered into farmout arrangements covering all its non-operated working interests under its Joint Exploration Agreements ("JEAs"; each, a "JEA") with Aethon in San Augustine and Angelina Counties. In May 2025, the farmout agreements covering the interests under the JEAs with Aethon terminated, and Aethon assumed the associated working interests as part of an amendment to the Partnership's JEAs with Aethon. In June 2025, the Partnership entered into a farmout arrangement covering all its non-operated working interests under its JEA with Revenant Energy in Angelina, Nacogdoches, and San Augustine Counties, under which the Partnership farmed out its undivided 35% working interest to an external capital provider.

Impairment of Oil and Natural Gas Properties

Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties (a "triggering event"). When assessing producing properties for impairment, if a triggering event has been identified, the Partnership compares the expected undiscounted projected future cash flows of the producing properties to the carrying amount of the producing properties to determine recoverability. When the carrying amount exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties. For the years ended December 31, 2025, 2024, and 2023, the Partnership did not identify any indicators of impairment and as such, no impairment of oil and natural gas properties were recognized. See "Note 6 - Fair Value Measurements" for additional information.

NOTE 5 — 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 December 31, 2025 and 2024, the Partnership's open derivatives 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 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 December 31, 2025 and 2024. See "Note 6 – 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 December 31, 2025, the Partnership had eight counterparties, all of which are lenders under the Credit Facility.

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

Classification	Balance Sheet Location	As of 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		$ 29,255	$ (6,262)	$ 22,993
Liabilities:				
Current liability	Commodity derivative liabilities, net	$ 6,066	$ (6,066)	$ —
Long-term liability	Commodity derivative liabilities, net	196	(196)	—
Total liabilities		$ 6,262	$ (6,262)	$ —

Classification	Balance Sheet Location	As of December 31, 2024 Gross Fair Value	Effect of Counterparty Netting	Net Carrying Value on Balance Sheet
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets, net	$ 4,866	$ (3,042)	$ 1,824
Long-term asset	Deferred charges and other long-term assets	768	(768)	—
Total assets		$ 5,634	$ (3,810)	$ 1,824
Liabilities:				
Current liability	Commodity derivative liabilities, net	$ 6,894	$ (3,042)	$ 3,852
Long-term liability	Commodity derivative liabilities, net	12,349	(768)	11,581
Total liabilities		$ 19,243	$ (3,810)	$ 15,433

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	For the year ended December 31, 2025	2024	2023
		(in thousands)	
Beginning fair value of commodity derivative instruments	$ (13,609)	$ 37,335	$ 28,941
Gain (loss) on oil derivative instruments	30,029	(6,591)	3,888
Gain (loss) on natural gas derivative instruments	17,562	861	87,229
Net cash paid (received) on settlements of oil derivative instruments	(12,102)	8,524	(2,653)
Net cash paid (received) on settlements of natural gas derivative instruments	1,113	(53,738)	(80,070)
Net change in fair value of commodity derivative instruments	36,602	(50,944)	8,394
Ending fair value of commodity derivative instruments	$ 22,993	$ (13,609)	$ 37,335

The Partnership had the following open derivative contracts for oil as of December 31, 2025:

Period and Type of Contract	Volume (MBbl)	Weighted Average Price (per Bbl)	Range (per Bbl)	
			Low	High
Oil Swap Contracts:				
2025				
Fourth quarter	185	$ 71.22	$ 70.02	$ 73.15
2026				
First quarter	615	64.39	62.00	67.35
Second quarter	615	64.39	62.00	67.35
Third quarter	615	64.39	62.00	67.35
Fourth quarter	615	64.39	62.00	67.35
2027				
First quarter	180	59.56	58.85	60.10
Second quarter	180	59.56	58.85	60.10
Third quarter	180	59.56	58.85	60.10
Fourth quarter	180	59.56	58.85	60.10

The Partnership had the following open derivative contracts for natural gas as of December 31, 2025:

Period and Type of Contract	Volume (BBtu)	Weighted Average Price (per MMBtu)	Range (per MMBtu)	
			Low	High
Natural Gas Swap Contracts:				
2026				
First quarter	12,600	$ 3.73	$ 3.50	$ 4.46
Second quarter	12,740	3.73	3.50	4.46
Third quarter	12,880	3.73	3.50	4.46
Fourth quarter	12,880	3.73	3.50	4.46
2027				
First quarter	6,300	$ 3.93	$ 3.85	$ 4.00
Second quarter	6,370	3.93	3.85	4.00
Third quarter	6,440	3.93	3.85	4.00
Fourth quarter	6,440	3.93	3.85	4.00

The Partnership entered into the following derivative contracts for oil subsequent to December 31, 2025:

Period and Type of Contract	Volume (MBbl)	Weighted Average Price (per MMBtu)	Range (per MMBtu)	
			Low	High
Oil Swap Contracts:				
2027				
First quarter	150	$ 59.74	$ 58.13	$ 61.20
Second quarter	150	59.74	58.13	61.20
Third quarter	150	59.74	58.13	61.20
Fourth quarter	150	59.74	58.13	61.20

NOTE 6 — 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 the fair value hierarchy for the years ended December 31, 2025 and 2024.

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 December 31, 2025 and 2024 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 5 – Commodity Derivative Financial Instruments" for additional information.

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	
	Level 1	Level 2	Level 3	Counterparty Netting	Total
			(in thousands)		
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)	—
As of December 31, 2024					
Financial Assets					
Commodity derivative instruments	$ —	$ 5,634	$ —	$ (3,810)	$ 1,824
Financial Liabilities					
Commodity derivative instruments	—	19,243	—	(3,810)	15,433

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 years ended December 31, 2025 and 2024. See "Note 4 — Oil and Natural Gas Properties." The Partnership's fair value assessments for recent acquisitions are included in "Note 4 — 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 years ended December 31, 2025 and 2024. There were no assets measured at fair value on a non-recurring basis, after initial recognition, for the years ended December 31, 2025 and 2024.

NOTE 7 — SIGNIFICANT OPERATORS

The Partnership leases mineral interests to exploration and production companies and participates in non-operated working interests when economic conditions are favorable. For the year ended December 31, 2025, Aethon represented approximately 14% of total oil and natural gas revenues. For the year ended December 31, 2024, Pioneer Natural Resources and XTO Energy, subsidiaries of ExxonMobil Corporation, collectively represented 13% of total oil and natural gas revenues. No single operator exceeded 10% of total oil and natural gas revenues for the year ended December 31, 2023.

If the Partnership lost a significant operator on its properties, such loss could impact revenue derived from its mineral and royalty interests and working interests. The loss of any single operator is mitigated by the Partnership’s diversified operator base.

NOTE 8 — 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 we terminate our hedge positions or sell oil and natural gas property interests that have a combined value exceeding 5% of the current borrowing base. In these circumstances, the borrowing base will be adjusted by the value attributed to the terminated hedge positions or the oil and natural gas property interests sold in the most recent borrowing base. The borrowing base was reaffirmed in April 2024, November 2024 and April 2025 at $580.0 million. After each redetermination the Partnership elected to maintain cash commitments at $375.0 million. In October 2025, the Partnership amended the Credit Facility to extend the maturity date from October 31, 2027 to October 31, 2030 and reduce the adjustment applied to secured overnight financing rate ("SOFR") loans. Concurrent with the Credit Facility amendment, the borrowing base was reaffirmed at $580.0 million and the Partnership elected to maintain cash commitments at $375.0 million. All existing banks in the lender syndicate elected to continue participating in the Credit Facility. No other significant terms were changed as part of the amendment. The next semi-annual redetermination is scheduled for April 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 December 31, 2024 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 7.03% during the year ended December 31, 2025 and the weighted-average interest rate was 7.50% during the year ended December 31, 2024. 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. As of December 31, 2025, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $154.0 million and $25.0 million at December 31, 2025 and 2024, respectively. The unused portion of the available borrowings under the Credit Facility was $221.0 million and $350.0 million at December 31, 2025 and 2024, respectively.

NOTE 9 — INCENTIVE COMPENSATION

Overview

The board of directors of the Partnership's general partner (the "Board") previously established a long-term incentive plan (the "2015 LTIP"), pursuant to which non-employee directors of the Partnership's general partner and certain employees and consultants of the Partnership and its affiliates were eligible to receive awards with respect to the Partnership's common units. The 2015 LTIP provided for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights either in tandem with an award or as a separate award, cash awards, and other unit-based awards. Any vesting terms associated with incentive awards granted under the 2015 LTIP were based on a predetermined schedule as approved by the Board or a committee thereof.

In 2025, the Board approved the adoption of a new long-term incentive plan to replace the 2015 LTIP following its expiration, which allows for the grant of the same type of awards and to the same service providers as was provided for under the 2015 LTIP. On June 12, 2025, our unitholders approved the Board’s adoption of the Black Stone Minerals, L.P. 2025 Long Term Incentive Plan (the “2025 LTIP”) at the Partnership’s 2025 Annual Meeting. Following the unitholder approval of the 2025 LTIP, no further awards will be granted under the 2015 LTIP. which expired on May 6, 2025, but which will continue to govern awards previously granted and still outstanding as of such expiration date.

Incentive compensation expense is included in the General and administrative line item on the consolidated statements of operations. The total compensation expense related to common unit grants is measured as the number of units granted multiplied by the grant-date fair value per unit. Incentive compensation expense is recognized using straight-line or accelerated attribution depending on the specific terms of the award agreements over the requisite service periods (generally equivalent to the vesting period) with actual forfeitures recognized as they occur.

Cash Awards

The Partnership also provides cash incentives in the form of an annual short-term incentive bonus for its executive officers and other employees. These awards are payable based on employee performance and the achievement of annual financial objectives measured against our internal operating plan established at the beginning of each fiscal year. However, final payouts are subject to reduction or increase by the Compensation Committee of the Board (the "Compensation Committee") for individual and team performance during the performance period.

Restricted Unit Awards

Restricted units awarded are subject to restrictions on transferability, customary forfeiture provisions, and time vesting provisions. Award recipients have all the rights of a unitholder in the Partnership, including the right to receive distributions thereon, if and when made by the Partnership. The grant-date fair value of these awards is recognized ratably using the straight-line attribution method.

The Compensation Committee annually approves a grant of awards to each of the executive officers of the Partnership's general partner and certain other employees. Consistent with previous awards the 2025 grant includes restricted common units subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through January 7, 2028. In January of each year, non-employee directors of the Partnership’s general partner receive compensation under the 2025 LTIP in the form of fully vested common units granted after each year of service.

The following table summarizes information about restricted units for the year ended December 31, 2025.

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2024	527,743	$ 15.48
Granted	392,928	15.11
Vested	(286,820)	14.78
Forfeited	(95,971)	15.58
Unvested at December 31, 2025	537,880	$ 15.57

The weighted-average grant-date fair value per unit for unit-based awards was $15.11, $16.39, and $16.03 for the years ended December 31, 2025, 2024, and 2023, respectively. As of December 31, 2025, unrecognized compensation cost associated with restricted unit awards was $4.6 million, which the Partnership expects to recognize over a weighted-average period of 1.74 years. The fair value of units vested for the years ended December 31, 2025, 2024, and 2023 was $4.1 million, $5.0 million, and $6.2 million, respectively. There were no cash payments made for vested units during the years ended December 31, 2025, 2024, and 2023.

Performance Unit Awards

The Compensation Committee also approves grants of restricted performance units that are subject to both performance-based and service-based vesting provisions. The number of common units issued to a recipient upon vesting of a restricted performance unit will be calculated based on performance against certain metrics that relate to the Partnership’s performance over each of the three calendar year performance periods commencing January 1 of the first calendar period. The target number of common units subject to each restricted performance unit is one; however, based on the achievement of performance criteria, the number of common units that may be received in settlement of each restricted performance unit can range from zero to two times the target number. The restricted performance units are eligible to become earned at the end of the required service period assuming the minimum performance metrics are achieved. Compensation expense related to the restricted performance unit awards is determined by multiplying the number of common units underlying such awards that, based on the Partnership's estimate of performance metrics by the measurement-date (i.e., the last day of each reporting period date) fair value and recognized using the accelerated or straight-line attribution methods, depending on the terms of the award. Distribution equivalent rights for the restricted performance unit awards are charged to partners' capital.

The following table summarizes information about performance units for the year ended December 31, 2025.

Performance units	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2024	800,162	$ 14.71
Granted[1]	393,443	15.10
Vested	(354,158)	12.78
Forfeited	(96,595)	15.57
Unvested at December 31, 2025	742,852	$ 15.73

[1] Includes 515 of additional performance units issued based on the final performance multiplier for awards that vested in the period.

The weighted-average grant-date fair value per unit for performance unit awards was $15.10, $15.11, and $14.54 for the years ended December 31, 2025, 2024, and 2023, respectively. Unrecognized compensation cost associated with performance unit awards was $3.7 million as of December 31, 2025, which the Partnership expects to recognize over a weighted-average period of 1.90 years. The fair value of performance units vested for the years ended December 31, 2025, 2024 and 2023 was $5.2 million, $6.3 million, and $8.0 million, respectively.

Aspirational Performance Unit Awards

In the first quarter of 2022, the Board approved a grant of awards to all employees dependent on the achievement of an aspirational production target to be measured in the fourth quarter of 2025 (the "Aspirational Awards"). The Aspirational Awards included performance cash awards and performance equity awards in the form of restricted performance units. The awards were contingent on achieving a production target of at least 42 Mboe per day of average daily royalty production in the fourth quarter or December 2025. As the production target was not met, all awards were forfeited, and no compensation expense was recognized for the year ended December 31, 2025.

Incentive Compensation Expense

The table below summarizes incentive compensation expense recorded in general and administrative expenses in the consolidated statements of operations for the years ended December 31, 2025, 2024, and 2023.

	Year Ended December 31,		
Incentive compensation expense	**2025**	**2024**	**2023**
		(in thousands)	
Cash — short and long-term incentive plan	$ 5,053	$ 4,940	$ 4,442
Equity-based compensation — restricted common units	4,210	3,982	3,852
Equity-based compensation — restricted performance units	3,247	2,284	4,774
Board of Directors incentive plan	2,163	2,298	2,203
Total incentive compensation expense	$ 14,673	$ 13,504	$ 15,271

NOTE 10 — EMPLOYEE BENEFIT PLANS

Black Stone Natural Resources Management Company, a subsidiary of the Partnership, sponsors a defined contribution 401(k) Profit Sharing Plan (the "401(k) Plan") for the benefit of substantially all employees of the Partnership. The 401(k) Plan became effective on January 1, 2001 and allows eligible employees to make tax-deferred pre-tax or post-tax contributions up to 90% of their annual compensation, not to exceed annual limits established by the Internal Revenue Service. The Partnership makes matching contributions of 100% of employee contributions, up to 5% of compensation. These matching contributions are subject to a graded vesting schedule, with 33% vested after one year, 66% vested after two years and 100% vested after three years of service with the Partnership. Following three years of service, future Partnership matching contributions vest immediately. The Partnership's contributions were $0.8 million, $0.7 million, and $0.6 million for the years ended December 31, 2025, 2024, and 2023, respectively.

NOTE 11 — 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 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 December 31, 2025 will be resolved without material adverse effect on the Partnership's financial condition or operations.

NOTE 12 — 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 $300.0 million.

The Series B cumulative convertible preferred units were initially entitled to quarterly distributions in an amount equal to 7.0% of the face amount of the preferred units per annum (the "Distribution Rate"). The Distribution Rate adjusted on November 28, 2023 and will be readjusted every two years thereafter (each, a "Readjustment Date"). 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 then-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 November 28, 2025. 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 $10.0 million based on the closing trading price of common units on the trading day immediately preceding the conversion notice date, or such lesser amount to the extent such exercise covers all of a holder's Series B cumulative convertible preferred units.

The Partnership has the option to redeem all or a portion (equal to or greater than $100.0 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 December 31, 2025 and 2024.

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

NOTE 13 — EARNINGS PER UNIT

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

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

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

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

	For the Year Ended December 31,		
	2025	2024	2023
	(in thousands, except per unit amounts)		
NET INCOME	$ 299,932	$ 271,326	$ 422,549
Distributions on Series B cumulative convertible preferred units	(29,466)	(29,466)	(21,776)
NET INCOME ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 270,466	$ 241,860	$ 400,773
ALLOCATION OF NET INCOME:			
General partner interest	$ —	$ —	$ —
Common units	270,466	241,860	400,773
	$ 270,466	$ 241,860	$ 400,773
NUMERATOR:			
Numerator for basic EPU - net income attributable to common unitholders	$ 270,466	$ 241,860	$ 400,773
Effect of dilutive securities	—	—	21,776
Numerator for diluted EPU - net income attributable to common unitholders after the effect of dilutive securities	$ 270,466	$ 241,860	$ 422,549
DENOMINATOR:			
Denominator for basic EPU - weighted average common units outstanding (basic)	211,667	210,684	209,970
Effect of dilutive securities	62	96	15,135
Denominator for diluted EPU - weighted average number of common units outstanding after the effect of dilutive securities	211,729	210,780	225,105
NET INCOME ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:			
Per common unit (basic)	$ 1.28	$ 1.15	$ 1.91
Per common unit (diluted)	$ 1.28	$ 1.15	$ 1.88

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:

	For the Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Potentially dilutive securities (common units):			
Series B cumulative convertible preferred units on an as-converted basis	15,072	15,072	—

NOTE 14 — 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, holders of Series B cumulative convertible preferred units in connection with any vote, consent or approval of the Series B cumulative convertible preferred units as a separate class, and persons who own 15% or more of any class as a result of any redemption or purchase of any other person's units or similar action by the Partnership or any conversion of the Series B cumulative convertible preferred units at the Partnership's option or in connection with a change of control, may not vote on any matter.

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

- *first*, to the holders of the Series B cumulative convertible preferred units in an amount equal to 7.0% of the face amount of the preferred units per annum, through November 27, 2023, then adjusting on November 28, 2023 and readjusting every two years thereafter, to a rate equal to the greater of (i) the rate in effect immediately prior to the relevant readjustment and (ii) the 10-year Treasury Rate as of such readjustment date plus 5.5% per annum (which rate adjusted to 9.8% effective November 28, 2023 and remained the same at 9.8% for November 28, 2025 and
- *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 condition, applicable legal requirements, available liquidity, and other appropriate factors. The Partnership made no repurchases under this program for the year ended December 31, 2025. The program is funded from the Partnership's cash on hand or through borrowings under the Credit Facility. Any repurchased units are canceled.

NOTE 15 — SUBSEQUENT EVENTS

Distribution

On February 5, 2026, the Board approved a distribution for the period from October 1, 2025 to December 31, 2025 of $0.300 per common unit. Distributions will be paid on February 25, 2026 to unitholders of record at the close of business on February 18, 2026.

Geographic Area of Operation

All the Partnership's proved reserves are located within the continental U.S., with the majority concentrated in Texas, Louisiana, and North Dakota. However, the Partnership also owns mineral and royalty interests and non-operated working interests in various producing and non-producing oil and natural gas properties in several other areas throughout the U.S. Therefore, the following disclosures about the Partnership's costs incurred and proved reserves are presented on a consolidated basis.

Costs Incurred in Oil and Natural Gas Property Acquisitions, Exploration, and Development Activities

Costs incurred in oil and natural gas property acquisition, exploration and development, whether capitalized or expensed, are presented below:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Acquisition Costs of Properties[1]:			
Proved	$ 346	$ 2,894	$ —
Unproved	114,122	107,537	14,605
Development Costs[1]	11,757	4,208	4,601
Total	$ 126,225	$ 114,639	$ 19,206

[1] Unproved properties include purchases of leasehold prospects.

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, and to provide facilities to extract, treat, and gather natural gas. Refer below for total capitalized costs and associated accumulated DD&A and impairment.

Oil and Natural Gas Capitalized Costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, and amortization, including impairments, are presented below:

	As of December 31,	
	2025	2024
	(in thousands)	
Proved properties	$ 2,015,631	$ 2,132,429
Unproved properties	1,063,709	973,028
Total	3,079,340	3,105,457
Accumulated depreciation, depletion, amortization, and impairment	(1,855,332)	(1,973,460)
Oil and natural gas properties, net	$ 1,224,008	$ 1,131,997

Oil and Natural Gas Reserve Information

The following table sets forth estimated net quantities of the Partnership's proved, proved developed, and proved undeveloped oil and natural gas reserves. Estimated reserves for the periods presented are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for the year in accordance with definitions and guidelines set forth by the SEC and the FASB. For estimates of oil reserves, the average WTI spot oil prices used were $66.01, $76.32, and $78.21 per barrel as of December 31, 2025, 2024, and 2023, respectively. These average prices are adjusted for quality, transportation fees, and market differentials. For estimates of natural gas reserves, the average Henry Hub prices used were $3.39, $2.13, and $2.64 per MMBtu as of December 31, 2025, 2024, and 2023, respectively. These average prices are adjusted for energy content, transportation fees, and market differentials. Natural gas prices are also adjusted to account for NGL revenue since there is not sufficient data to account for NGL volumes separately in the reserve estimates. These reserve estimates exclude insignificant natural gas liquid quantities owned by the Partnership. When taking these adjustments into account, the average adjusted prices weighted by production over the remaining lives of the properties were $63.40 per barrel for oil and $3.37 per Mcf for natural gas as of December 31, 2025, $74.14 per barrel for oil and $2.22 per Mcf for natural gas as of December 31, 2024, and $76.90 per barrel for oil and $2.63 per Mcf for natural gas as of December 31, 2023.

	Crude Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)
Net proved reserves at December 31, 2022	19,184	269,586	64,115
Revisions of previous estimates [1]	675	(20,578)	(2,754)
Extensions, discoveries and other additions[2]	2,989	87,935	17,645
Production	(3,757)	(64,647)	(14,532)
Net proved reserves at December 31, 2023	19,091	272,296	64,474
Revisions of previous estimates[1]	119	(25,218)	(4,084)
Purchases of minerals in place[3]	10	314	62
Sales of minerals in place[4]	(163)	(1,250)	(371)
Extensions, discoveries and other additions[2]	2,015	56,323	11,402
Production	(3,606)	(62,984)	(14,103)
Net proved reserves at December 31, 2024	17,466	239,481	57,380
Revisions of previous estimates[1]	669	(2,732)	214
Purchases of minerals in place[3]	70	943	227
Sales of minerals in place[4]	(24)	(75)	(37)
Extensions, discoveries and other additions[2]	1,714	47,877	9,693
Production	(3,259)	(56,237)	(12,632)
Net proved reserves at December 31, 2025	16,636	229,257	54,845
Net Proved Developed Reserves			
December 31, 2023	19,091	228,061	57,101
December 31, 2024	17,466	220,901	54,283
December 31, 2025	16,241	191,632	48,179
Net Proved Undeveloped Reserves			
December 31, 2023	—	44,235	7,373
December 31, 2024	—	18,580	3,097
December 31, 2025	395	37,625	6,666

[1] Revisions of previous estimates include technical revisions due to changes in commodity prices, historical and projected performance and other factors. The most notable revisions are related to changes in commodity pricing.

[2] Includes extensions and additions related to drilling activities in multiple areas, primarily within the Haynesville/Bossier play trend and the Permian Basin.

[3] Includes the acquisition of mineral and royalty reserves primarily within the Haynesville/Bossier play trend.

[4] Includes divestitures of working interest reserves primarily within the Austin Chalk play trend.

Standardized Measure of Discounted Future Net Cash Flows

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the 12-month unweighted average of first-day-of-the-month commodity prices for the periods presented. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials. Future cash inflows are computed by applying applicable prices relating to the Partnership's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. There are no federal income taxes deducted in the calculation of the standardized measure because the Partnership is not subject to them. Future income tax expense includes applicable state taxes. See "Note 2 – Summary of Significant Accounting Policies" for additional information.

	Year Ended December 31,		
	2025	2024	2023
		(in thousands)	
Future cash inflows	$ 1,828,128	$ 1,827,316	$ 2,184,038
Future production costs	(178,506)	(164,886)	(211,826)
Future development costs	(63,833)	(62,137)	(61,723)
Future income tax expense	(5,753)	(5,433)	(6,259)
Future net cash flows (undiscounted)	1,580,036	1,594,860	1,904,230
Annual discount 10% for estimated timing	(690,837)	(726,773)	(884,720)
Total	$ 889,199	$ 868,087	$ 1,019,510

The following summarizes the principal sources of change in the standardized measure of discounted future net cash flows:

	Year Ended December 31,		
	2025	2024	2023
		(in thousands)	
Standardized measure, beginning of year	$ 868,087	$ 1,019,510	$ 1,665,011
Sales, net of production costs	(351,813)	(367,686)	(420,228)
Net changes in prices and production costs related to future production	44,268	(51,740)	(649,695)
Extensions, discoveries and improved recovery, net of future production and development costs	179,769	174,145	295,413
Previously estimated development costs incurred during the period	—	—	—
Revisions of estimated future development costs	(551)	(123)	(4,221)
Revisions of previous quantity estimates, net of related costs	4,526	(65,903)	(78,139)
Accretion of discount	87,104	102,292	167,064
Purchases of reserves in place, less related costs	3,700	572	—
Sales of reserves in place	(795)	(5,194)	—
Changes in timing and other	54,904	62,214	44,305
Net increase (decrease) in standardized measures	21,112	(151,423)	(645,501)
Standardized measure, end of year	$ 889,199	$ 868,087	$ 1,019,510

The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a significant amount of estimates and assumptions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from historical prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.