UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2023

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 $2,692,990,488 on June 30, 2023, the last business day of the registrant's most recently completed second fiscal quarter, based on a closing price of $15.95 per unit as reported by the New York Stock Exchange on such date. As of February 16, 2024, 210,313,477 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.

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 us 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 where we have concentrated acreage positions;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services, or personnel;
- restrictions on the use of water for hydraulic fracturing;
- the availability of pipeline capacity and transportation facilities;
- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- future operating results;
- future cash flows and liquidity, including our ability to generate sufficient cash to pay quarterly distributions;
- exploration and development drilling prospects, inventories, projects, and programs;
- operating hazards faced by our operators;
- the ability of our operators to keep pace with technological advancements;
- conservation measures and general concern about the environmental impact of the production and use of fossil fuels;
- cybersecurity incidents, including data security breaches or computer viruses; and
- certain factors discussed elsewhere in this 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.

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.

We own mineral interests in approximately 16.8 million gross acres, with an average 43.5% ownership interest in that acreage. We also own NPRIs in 1.8 million gross acres and ORRIs 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 68,000 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.

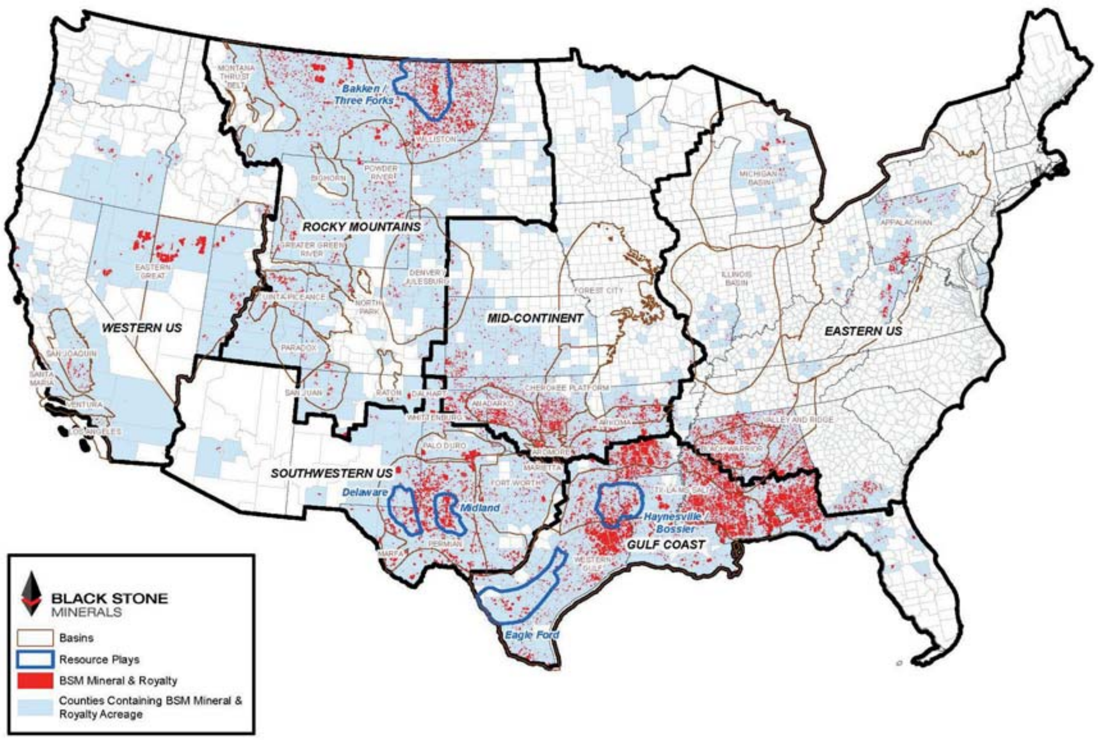
We are a publicly traded Delaware limited partnership formed on September 16, 2014. Our common units trade on the New York Stock Exchange under the symbol "BSM."

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, 2023, our total estimated proved oil and natural gas reserves were 64,474 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, 2023, approximately 89% were proved developed reserves and approximately 11% were proved undeveloped reserves. At December 31, 2023, 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, 2023, approximately 25% 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. In 2022, we entered into agreements with multiple operators to drill wells in the Austin Chalk in East Texas, where we have significant acreage positions. 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 6% of our total production volumes during the year ended December 31, 2023. As of December 31, 2023, we owned non-operated working interests in 3,352 gross (377 net) wells.

Our 2024 capital expenditure budget associated with our non-operated working interests is expected to be approximately $2.3 million. The majority of this capital is anticipated to be spent on workovers and recompletions on existing wells in which we own a working interest.

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.

Farmout Agreements

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

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

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, 2023							
	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	7,927,137	52.1 %	553,369	4.8 %	191,011	3.6 %	325,500	76,242
Southwestern U.S.	2,764,885	25.3 %	988,675	3.9 %	193,734	1.7 %	18,122	12,121
Rocky Mountains	2,121,611	15.4 %	243,295	3.4 %	798,728	2.4 %	90,328	15,210
Eastern U.S.	1,649,953	47.6 %	1,727	4.0 %	74,247	1.3 %	13,468	1,375
Mid-Continent	1,307,718	34.6 %	38,332	4.3 %	269,750	3.6 %	53,391	31,083
Western U.S.	1,025,864	89.1 %	331	1.8 %	28,029	3.3 %	—	—
Total	16,797,168	43.5 %	1,825,729	4.1 %	1,555,499	2.6 %	500,809	136,031

[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 BSM Land Region. Our weighted average royalty interest for all of our mineral interests is approximately 21%, 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, 2023[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	2023	2022	2021	2023	2022	2021
Gulf Coast	14,771	1,461	23,600	21,019	19,539	1,614	2,108	3,820
Southwestern U.S.	26,048	631	6,417	5,703	5,442	67	69	134
Rocky Mountains	15,422	839	4,609	4,545	5,138	519	534	585
Eastern U.S.	1,590	6	748	835	754	6	3	16
Mid-Continent	9,160	415	1,824	1,972	1,796	170	84	555
Western U.S.	565	—	238	261	267	—	—	—
Total	67,556	3,352	37,436	34,335	32,936	2,376	2,798	5,110

[1] We own both mineral and royalty interests and working interests in 2,029 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 75% of our aggregate production for the year ended December 31, 2023.

- ***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, 2023							
	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	397,745	17.0 %	38,624	1.4 %	12,168	1.3 %	52,043	6,671
Haynesville/Bossier	401,763	61.5 %	28,358	2.8 %	26,676	5.3 %	154,267	28,499
Permian-Midland	221,630	4.9 %	128,401	2.3 %	99,864	0.4 %	160	4
Permian-Delaware	134,287	9.3 %	39,103	2.6 %	5,163	3.1 %	2,482	1,071
Eagle Ford	67,414	14.4 %	106,301	1.3 %	48,220	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 21%, 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			Mineral and Royalty Interests			Working Interests		
	Gross Well Count as of December 31, 2023[1]		Average Daily Production (Boe/d) for the Year Ended December 31,			Average Daily Production (Boe/d) for the Year Ended December 31,		
	MRI Wells[2]	WI Wells	2023	2022	2021	2023	2022	2021
Bakken/ Three Forks	4,428	550	3,507	3,458	3,848	361	377	408
Haynesville/Bossier	1,416	153	18,360	16,867	15,935	1,108	1,504	3,179
Permian-Midland	3,774	2	2,991	2,623	2,457	—	—	—
Permian-Delaware	1,039	11	2,419	1,902	1,725	19	24	39
Eagle Ford	1,038	27	1,084	1,122	838	8	8	15

[1] We own both mineral and royalty interests and working interests in 659 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, 2023, 2022, and 2021 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 4 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 as of December 31, 2023 is attached as an exhibit 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. Garrett Gremillion, our Vice President, Engineering, was primarily responsible for overseeing the preparation of our reserve estimates for 2023, 2022 and 2021. Mr. Gremillion is a petroleum engineer with approximately 14 years of reservoir-engineering experience.

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 our Vice President, Engineering; 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, 2023, 2022, and 2021 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 $78.21, $94.14, and $66.55 per barrel as of December 31, 2023, 2022, and 2021, 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 $2.64, $6.36, and $3.60 per MMBtu as of December 31, 2023, 2022, and 2021, 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 $76.90 per barrel for oil and $2.63 per Mcf for natural gas as of December 31, 2023, $92.01 per barrel for oil and $6.50 per Mcf for natural gas as of December 31, 2022, and $63.17 per barrel for oil and $3.37 per Mcf for natural gas as of December 31, 2021.

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,		
	2023	2022	2021
		(Unaudited)	
Estimated proved developed:			
Oil (MBbls)	19,091	19,184	19,111
Natural gas (MMcf)	228,061	236,529	224,222
Total (MBoe)	57,101	58,606	56,481
Estimated proved undeveloped:			
Oil (MBbls)	—	—	60
Natural gas (MMcf)	44,235	33,057	19,695
Total (MBoe)	7,373	5,509	3,343
Estimated proved reserves:			
Oil (MBbls)	19,091	19,184	19,171
Natural gas (MMcf)	272,296	269,586	243,917
Total (MBoe)	64,474	64,115	59,824
Percent proved developed	88.6 %	91.4 %	94.4 %

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, 2023 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, 2023, our PUDs comprised 44,235 MMcf of natural gas, or 7,373 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, 2023 (in MBoe):

	Estimated Proved Undeveloped Reserves
	(Unaudited)
As of December 31, 2022	5,509
Acquisitions of reserves	—
Divestiture of reserves	—
Extensions and discoveries	7,373
Revisions of previous estimates	(488)
Transfers to estimated proved developed	(5,021)
As of December 31, 2023	7,373

New PUD reserves totaling 7,373 MBoe were added during the year ended December 31, 2023, resulting from development activities in the Haynesville/Bossier play. In 2023 we did not acquire or divest any PUD reserves.

During the year ended December 31, 2023, we had no upward revisions to PUD reserves and converted 5,021 MBoe of PUD reserves to PDP reserves.

During the year ended December 31, 2023, no costs were incurred relating to the development of locations that were classified as PUDs as of December 31, 2022. The PUDs that were developed during 2023 were primarily Haynesville/Bossier PUDs in which our working interest was farmed out. Additionally, during the year ended December 31, 2023, we incurred $4.1 million drilling, completing, and recompleting other wells that were not classified as PUDs as of December 31, 2022. There are no estimated future development costs projected for the development of PUD reserves associated with our working interests as of December 31, 2023. All our PUD drilling locations as of December 31, 2023 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 received and approved an AFE. As of December 31, 2023, our PUD reserves consists of 26 wells in various stages of drilling or completions. As of December 31, 2023, approximately 11% 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, 2023, 26% of our production and 59% 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 41% 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,		
	2023	2022	2021
Production:			
Oil and condensate (MBbls)	3,757	3,591	3,646
Natural gas (MMcf)[1]	64,647	59,778	61,445
Total (MBoe)	14,532	13,554	13,887
Average daily production (MBoe/d)	39.8	37.1	38.0
Realized Prices without Derivatives:			
Oil and condensate (per Bbl)	$ 76.74	$ 93.65	$ 64.67
Natural gas and natural gas liquids sales (per Mcf)[1]	$ 3.10	$ 7.28	$ 4.16
Unit Cost per Boe:			
Production costs and ad valorem taxes	$ 3.92	$ 4.89	$ 3.59

[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, 2023[1]		
	Mineral and Royalty Interests	Working Interests	
Well Type	Gross	Gross	Net
Oil	38,775	2,052	129
Natural Gas	28,781	1,300	248
Total	67,556	3,352	377

[1] We own both mineral and royalty interests and working interests in 2,029 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, 2023:

BSM Land Region	Developed Acreage[1]	Undeveloped Acreage[1]	Total Acreage[1]
Gulf Coast	449,539	8,221,978	8,671,517
Southwestern U.S.	629,847	3,317,447	3,947,294
Rocky Mountains	888,909	2,274,725	3,163,634
Eastern U.S.	84,242	1,641,685	1,725,927
Mid-Continent	524,762	1,091,038	1,615,800
Western U.S.	28,340	1,025,884	1,054,224
Total	2,605,639	17,572,757	20,178,396

[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, 2023:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
BSM Land Region	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	310,166	71,433	15,334	4,809	325,500	76,242
Southwestern U.S.	18,122	12,121	—	—	18,122	12,121
Rocky Mountains	89,492	15,210	836	—	90,328	15,210
Eastern U.S.	13,468	1,375	—	—	13,468	1,375
Mid-Continent	53,391	31,083	—	—	53,391	31,083
Western U.S.	—	—	—	—	—	—
Total	484,639	131,222	16,170	4,809	500,809	136,031

Undeveloped Acreage

The following table lists the net undeveloped acres, the net acres expiring in the years ending December 31, 2024, 2025, and 2026, and, where applicable, the net acres expiring that are subject to extension options:

	2024 Expirations		2025 Expirations		2026 Expirations	
Net Undeveloped Acreage	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.
4,809	1,392	1,754	64	1,596	3	—

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,		
	2023	**2022**	**2021**
Gross development wells:			
Productive	1.0	1.0	2.0
Dry	—	—	—
Total	1.0	1.0	2.0
Net development wells:			
Productive	0.2	0.1	0.2
Dry	—	—	—
Total	0.2	0.1	0.2
Gross exploratory wells:			
Productive	—	—	—
Dry	—	—	1.0
Total	—	—	1.0
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	1.0
Total	—	—	1.0

As of December 31, 2023, 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 statues 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, and any increase in scope 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 limited 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 in the United States and in foreign countries, 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 ("GHGs") 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. However, the current administration has highlighted addressing climate change as a priority and has issued several executive orders addressing climate change and the EPA has adopted regulations 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 from certain petroleum and natural gas system sources in the United States.

The regulation of methane from oil and gas facilities has been subject to uncertainty in recent years. In response to a Biden administration executive order calling for the EPA to revise federal regulations regarding methane, the EPA finalized more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc, in December 2023. It is likely the rule will be subject to legal challenge.

Relatedly, the Inflation Reduction Act of 2022 ("IRA") appropriates significant federal funding for renewable energy initiatives, alongside amending the CAA to impose a first-time fee on the emissions of methane from sources required to report their GHG emissions to the EPA.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, the United Nations-sponsored "Paris Agreement," requires member states to submit non-binding, individually determined reduction goals every five years after 2020. And, at the most recent Conference of the Parties of the UN Framework Convention on Climate Change, (COP28), parties signed into an agreement to transition "away from fossil fuels in energy systems in a just, orderly, and equitable manner" and increase renewable energy capacity so as to achieve net zero by 2050, although no timeline for doing so was set.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate-change-related pledges made by some candidates now in political office. These have included promises to limit emissions and curtail certain production of oil and natural gas, such as adopted legislation by both the states of New York and Washington (and implemented in New York City) to phase in mandates that newly constructed buildings be "zero emission" or "all-electric." Other actions that could be pursued by the current administration may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure and the permitting of LNG export facilities. In January 2024, the Biden administration announced that approvals for pending and future applications for certain new LNG facilities were being paused pending a review by the Department of Energy (“DOE”) that aims to assess whether climate effects should be more heavily considered in the authorization process for such LNG export projects. It is too early to know the outcome of this review and any impact the results of such review may have on LNG export growth. 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.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Many of the largest U.S. banks have made "net zero" carbon emissions commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps to quantify and reduce those emissions. Additionally, financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. For example, in October 2023, the Federal Reserve, Office of the Comptroller of the Currency and the Federal Deposit Insurance Corp released a finalized set of principles guiding financial institutions with $100 billion or more in assets on the management of physical and transition risks associated with climate change. 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 of 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 if they become subject to water use curtailments in response to drought, or demand for their products, such as to the extent warmer winters reduce the demand for heating purposes.

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 recently the EPA and other federal agencies have asserted jurisdiction over certain aspects of hydraulic fracturing.

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. 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 increasing public 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.

Marketing and Major Customers

If we were to lose a significant customer, 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 customer base. In 2023, no single customer accounted for more than 10% of our total oil and gas revenues. The following table indicates our significant customers that accounted for 10% or more of our total oil and natural gas revenues for the periods indicated:

	2022	2021
XTO Energy Inc.	12%	19%

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, 2023, Black Stone Management had 108 full-time employees and 18 contractors. Our largest departments are Accounting and Land Administration, which account for 33 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 (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. Our "extended leadership" group, consisting of 28 employees, also receives 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 recently introduced recognition program to celebrate milestone service awards and other moments of excellence.

Hybrid Work Environment. During the last three years we have added additional work flexibility for the majority of our employees, and those arrangements became a permanent part of our work environment in 2023. Employees have the ability to work outside of the office on Monday and Friday, while working in the office Tuesday through Thursday during core business hours. This adjustment has allowed employees to retain the greater work-life balance they found during the pandemic, and we believe these decisions, as well as our robust compensation and benefits programs, have allowed us to retain a large percentage of our workforce and to 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, 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;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- global geopolitical conflict, including the ongoing war in Ukraine, the conflict in the Middle East 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, 2023		During the Five Years Prior to 2023		As of December 31,		
	High	Low	High[2]	Low[3]	2023	2022	2021
WTI spot crude oil ($/Bbl)[1]	$ 93.67	$ 66.61	$ 123.64	$ 8.91	$ 71.89	$ 80.16	$ 75.33
Henry Hub spot natural gas ($/MMBtu)[1]	3.78	1.74	23.86	1.33	2.58	3.52	3.82

[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 2020. Excludes the period in April 2020 when WTI briefly traded in negative territory.

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 59% of our 2023 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, 2023, 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 29, 2023, the last trading day of 2023, the WTI spot market price of oil was $71.89. 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 fluctuations in demand as a result of the COVID-19 pandemic. 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 41% of our 2023 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, 2023, natural gas prices at Henry Hub have ranged from a high of $23.86 per MMBtu in 2021 to a low of $1.33 per MMBtu in 2020. On December 29, 2023, the last trading day of 2023, the Henry Hub spot market price of natural gas was $2.58 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 rising 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.

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 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 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 oil 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.

In January 2024, the Biden administration announced that approvals for pending and future applications for certain new LNG facilities were being paused pending a review by the DOE that aims to assess whether climate effects should be more heavily considered in the authorization process for such LNG export projects. It is too early to know the outcome of this review and any impact the results of such review may have on LNG export growth but slowing LNG export growth could adversely affect the demand for our products.

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, 2023, 2022, and 2021 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, 2023, 2022, and 2021 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, 2023, 2022, and 2021, 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, 2023, 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 2023, we generated 10% of our royalty revenues and 19% 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; or
- delay or cancellation of construction or operation of LNG export facilities in the Gulf of Mexico.

In December 2023, we received notice that Aethon Energy ("Aethon") was exercising the "time-out" provisions under its joint exploration agreements with us in Angelina and San Augustine counties in East Texas. When natural gas prices fall below specified thresholds, Aethon may elect to temporarily suspend its drilling obligations for up to nine consecutive months and a maximum of 18 total months in any 48-month period. Aethon has not previously invoked the time-out provisions under the agreements. For more information, please read Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments."

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, 2023, we had no outstanding borrowings and the aggregate maximum credit amounts of the lenders were $1.0 billion. Our borrowing base determined by the lenders under our Credit Facility in October 2023 was $580.0 million and we elected to maintain cash commitments at $375.0 million. The next semi-annual redetermination is scheduled for April 2024. 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, executed 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; 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, including those directed at the threat of climate change. 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 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 reduce the amount of cash distributions 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 increasing public 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.

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

Increasing attention to, and social expectations on, companies to address climate change and other environmental and social impacts, investor and societal explanations regarding voluntary 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. Increasing 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. 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 an additional description of some of the many ESG-related developments that may affect us, our operators, and/or the oil and gas sector more generally.

Additionally, we may receive pressure from investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles. In March 2022, the U.S. Securities and Exchange Commission ("SEC") released a proposed rule that would establish a framework for the reporting of climate risks, targets, and metrics. A final rule is expected to be released in 2024. We cannot predict what any such final rule may require. As proposed, the SEC climate rule would impose burdensome and potentially costly emissions and other data gathering and reporting requirements on our operations, including, but not limited to, those related to risks to our operators arising from the physical impacts of climate change (i.e., flooding, water stress, extreme temperatures). To the extent the rule imposes additional reporting obligations, we could face increased costs. Separately, the SEC has announced that it is scrutinizing existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege an issuer's climate disclosures are misleading, deceptive or deficient. Such agency action could also increase the potential for private litigation. Relatedly, California has enacted new laws requiring additional disclosure with respect to certain climate-related risks and GHG emissions reduction claims. Non-compliance with these new laws may result in the imposition of substantial fines or penalties. Other states are considering similar laws. Any new laws or regulations imposing more stringent requirements on our business related to the disclosure of climate-related risks may result in reputation harms among certain stakeholders if they disagree with our approach to mitigating climate-related risks, increased compliance costs resulting from the development of any disclosures, 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.

Relatedly, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us or our customers and to the diversion of investment or other industries which could have a negative impact on our unit price and/or our access to and costs of capital. Additionally, institutional lenders may decide not to provide funding for fossil fuel energy companies or the corresponding infrastructure projects based on climate change related concerns, which could affect our access to capital for potential growth projects. Moreover, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively or recruit or retain employees, which may adversely affect our operations.

Finally, public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly 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. For example, in March 2021, the SEC established the Climate and ESG Task Force in the Division of Enforcement to identify and address potential ESG-related misconduct, including greenwashing. Certain non-governmental organizations and other private actors have also filed lawsuits under various securities and consumer protection laws alleging that certain ESG-statements, goals, or standards were misleading, false, or otherwise deceptive. Moreover, the Federal Trade Commission in August 2022 indicated its intent to issue revised "Green Guides" which will likely address greenwashing risks arising from ESG-related matters. As a result, we may face increased litigation risks from private parties and governmental authorities related to our ESG efforts. In addition, any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further regulatory focus and scrutiny.

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 equal to 7.0% of the face amount of the preferred units per annum through November 27, 2023, adjusted to 9.8% effective November 28, 2023 and subject to readjustment every two years thereafter, 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 BSMC 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, 2023, we had 209,991,223 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, 2023 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. Distributions to our common unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, or deductions 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 return 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. Further, while unitholders of publicly traded partnerships are, subject to certain limitations, generally entitled to a deduction equal to 20% of their allocable share of a publicly traded partnership’s “qualified business income” (as further discussed below), this deduction is scheduled to expire with respect to taxable years beginning after December 31, 2025.

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.

Even if you, as a common unitholder, do not receive any cash distributions from us, you will be required to pay taxes on your share of our taxable income.

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. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale and our cash available for distribution would not increase. Similarly, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in “cancellation of indebtedness income” being allocated to our common unitholders as taxable income without any increase in our cash available for distribution. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax due from you with respect to 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 future 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 and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions 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.

For taxable years beginning after December 31, 2017 and ending on or before December 31, 2025, an individual common unitholder is entitled to a deduction equal to 20% of his or her allocable share of our "qualified business income". 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. The IRS may challenge our treatment of royalty income as qualifying for the deduction.

Although our counsel has advised us that under current law our royalty income should qualify for the deduction, no assurances can be given that the IRS will not challenge our treatment of royalty income as qualifying for the deduction.

General Risk Factors

We have and will continue to incur increased costs as a result of being a publicly traded partnership.

As a publicly traded partnership, we have and will continue to incur significant legal, accounting, and other expenses that we did not incur prior to the IPO. In addition, the Sarbanes-Oxley Act, as well as rules implemented by the SEC and the NYSE, require publicly traded entities to maintain various corporate governance practices that further increase our costs. Before we are able to make distributions to our unitholders, we must first pay or reserve for our expenses, including the costs of being a publicly traded partnership. As a result, the amount of cash we have available to distribute to our unitholders will be affected by the costs associated with being a publicly traded partnership.

Following the IPO, we became subject to the public reporting requirements of the Securities Exchange Act of 1934 (the "Exchange Act"). These requirements have increased our legal and financial compliance costs.

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" and, together with the VP IT, 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 over 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 regularly 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 Manager of the 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 NIST and 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 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

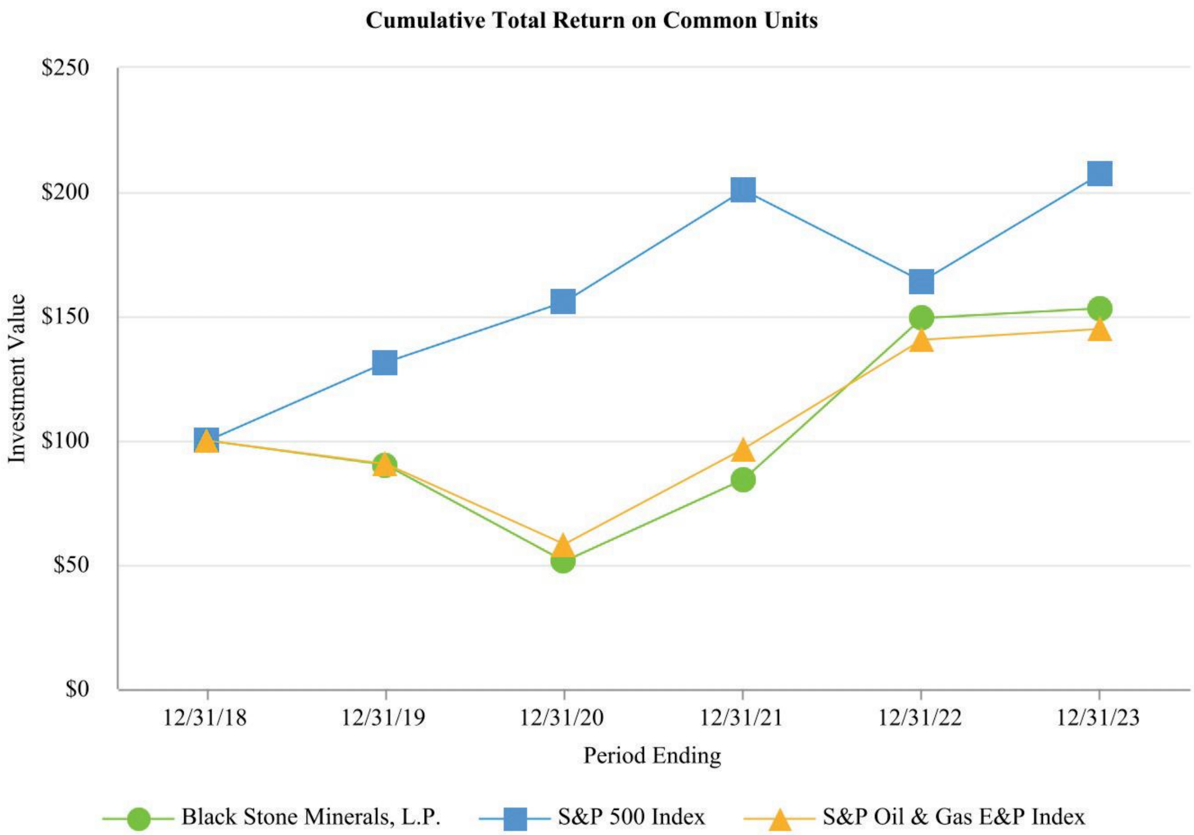
Not applicable.

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 16, 2024, there were 210,313,477 common units outstanding held by 368 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 16, 2024, 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, 2018. Cumulative return is computed assuming reinvestment of distributions.



Comparison of Cumulative Total Return
Assumes Initial Investment of $100

	As of December 31,					
	2018	2019	2020	2021	2022	2023
Black Stone Minerals, L.P.	$ 100.00	$ 90.20	$ 51.09	$ 84.40	$ 149.18	$ 153.17
S&P 500 Index	100.00	131.49	155.68	200.37	164.08	207.21
S&P Oil & Gas E&P Index	100.00	90.56	58.06	96.72	140.31	144.91

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 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, adjusted to 9.8% effective November 28, 2023 and subject to readjustment every two years thereafter; 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, our executed farmout agreements, 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 holders of our Series B cumulative convertible preferred units were initially entitled to receive cumulative quarterly distributions in an amount equal to 7.0% of the face amount of the preferred units per annum (the “Distribution Rate”). On November 28, 2023, the Distribution Rate was adjusted to 9.8% and will be readjusting 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. We cannot pay any distributions on any junior securities, including any of our 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 until February 26, 2024 at a redemption price of $21.41 per Series B cumulative convertible preferred unit, which is equal to 105% of par value. Thereafter, we may redeem the preferred units at par value, equal to $20.39, within a 90-day period on each second anniversary following November 28, 2023.

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 2023 and 2022. For the discussion of changes from 2022 to 2021 and other financial information related to 2021, refer to Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our 2022 Annual Report on Form 10-K, which was filed with the SEC on February 22, 2023.

Overview

As of December 31, 2023, 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 68,000 producing wells. We also own non-operated working interests, a significant portion of which are on our positions where we also have a mineral and royalty interest. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when control of the oil and natural gas produced is transferred to the customer and collectability of the sales price is reasonably assured. Our other sources of revenue include mineral lease bonus and delay rentals, which are recognized as revenue according to the terms of the lease agreements.

Recent Developments

Shelby Trough Development Update

In Angelina County, Texas, 24 wells are currently producing under our development agreement with Aethon, and another 20 wells are being drilled or completed. Under a separate development agreement with Aethon in San Augustine County, Texas, 13 wells are currently producing, and another four wells are either drilling or awaiting completion operations.

In December 2023, we received notice that Aethon was exercising the "time-out" provisions under its joint exploration agreements with us in Angelina and San Augustine counties in East Texas. When natural gas prices fall below specified thresholds, Aethon may elect to temporarily suspend its drilling obligations for up to nine consecutive months and a maximum of 18 total months in any 48-month period. Aethon has not previously invoked the time-out provisions under the agreements.

The time-out provisions apply only to drilling obligations and associated development activity occurring after December 2023. Based on ongoing discussions with Aethon, we do not expect material changes for wells on which drilling operations had begun prior to the invocation of the time-out in December 2023. We continue working closely with Aethon to finalize development plans going forward and assess the effect of the temporary suspension of drilling obligations and any potential longer-term impacts.

Austin Chalk Update

We own a large mineral position in the Brookeland Austin Chalk play in East Texas. We have entered into agreements with multiple operators to drill wells in the areas of the Austin Chalk in East Texas, where we have significant acreage positions. The results of the test program in the Brookeland Field demonstrated that modern completion technology has the potential to improve production rates and increase reserves when compared to the vintage, unstimulated wells in the Austin Chalk formation. To date, 29 wells with modern completions are now producing in the field.

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 and costless collar contracts.

Commodity prices during 2023 decreased from the corresponding prior period due to several factors, including reduced demand for natural gas and rising global oil inventories. The U.S. Energy Information Administration ("EIA") forecasts natural gas prices to be slightly higher in 2024 because of slowing growth in natural gas production and increasing U.S. LNG exports, particularly following the addition of new export capacity expected toward the end of the year. The slowing growth reflects a drop in natural gas production associated with oil drilling in the Permian Basin. However, the EIA expects upward price pressures will be limited by relatively flat consumption of natural gas in the electric power sector and persistently high inventories. For much of 2023, oil prices were relatively flat. In September 2023, oil prices increased after Saudi Arabia extended its voluntary crude oil production cuts through the end of the year and U.S. commercial crude oil inventories fell to the lowest levels since early 2022. Despite reduced production targets by members of OPEC+, prices decreased in the fourth quarter based on ongoing concerns about global oil demand growth and on rising global oil inventories. The EIA expects that while OPEC+ production cuts will lead to global oil inventory withdrawals during the first quarter of 2024, global inventories will build over the final three quarters of 2024 as slowing demand growth once again is outpaced by rising supply growth. However, heightened tensions around the critical Red Sea shipping channel and other developments in the Middle East have added upward price pressure since early December and have the potential to disrupt global oil trade flows and drive up global oil prices further should those tensions persist or escalate. Given the dynamic nature of these events, along with the volatile geopolitical conflicts in Ukraine, we cannot reasonably estimate how long these 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:

	2023			
Benchmark Prices	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot crude oil ($/Bbl)[1]	$ 71.89	$ 90.77	$ 70.66	$ 75.68
Henry Hub spot natural gas ($/MMBtu)[1]	$ 2.58	$ 2.68	$ 2.48	$ 2.10

[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:

	2023			
U.S. Rotary Rig Count[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	500	502	545	592
Natural gas	120	116	124	160
Other	2	5	5	3
Total	622	623	674	755

[1] Source: Baker Hughes Incorporated

Natural Gas Storage

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

Historically, natural gas supply and demand fluctuates on a seasonal basis. From April to October, when the weather is warmer and natural gas demand is lower, natural gas storage levels generally increase. From November to March, storage levels typically decline as utility companies draw natural gas from storage to meet increased heating demand due to colder weather. In order to maintain sufficient storage levels for increased seasonal demand, a portion of natural gas production during the summer months must be used for storage injection. The portion of production used for storage varies from year to year depending on the demand from the previous winter and the demand for electricity used for cooling during the summer months. The EIA forecasts that inventories will conclude the withdrawal season, which is the end of March 2024, at 1.9 Tcf, or 15% higher than the five-year average. The EIA expects inventories will rise to 4.0 Tcf at the end of October 2024, which would be 6% higher than the five-year average.

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

	2023			
Region[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
	(Bcf)			
East	799	847	643	335
Midwest	968	991	705	421
Mountain	228	239	173	80
Pacific	280	278	216	73
South Central	1,201	1,090	1,141	921
Total	3,476	3,445	2,878	1,830

[1] Source: EIA

Natural Gas Exports

The EIA expects exports of natural gas, both by pipeline and as LNG, will increase in 2024. The EIA forecasts average exports of 12.1 Bcf per day for 2024, a 2% increase from 2023 levels.

In January 2024, the Biden administration announced that approvals for pending and future applications for certain new LNG facilities were being paused pending a review by the DOE that aims to assess whether climate effects should be more heavily considered in the authorization process for such LNG export projects. It is too early to know the outcome of this review and any impact the results of such review may have on LNG export growth.

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

<u>Factors Affecting the Sales Price of Oil and Natural Gas</u>

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.

Hedging

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

Our open derivative contracts consist of fixed-price swap contracts. Under fixed-price swap contracts, a counterparty is required to make a payment to us if the settlement price is less than the swap strike price. Conversely, we are required to make a payment to the counterparty if the settlement price is greater than the swap strike price. If we have multiple contracts outstanding with a single counterparty, unless restricted by our agreement, we will net settle the contract payments.

We may employ contractual arrangements other than fixed-price swap contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue. Our open oil and natural gas derivative contracts as of December 31, 2023 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 up to 90% of such volumes for the first 24 months, 70% for months 25 through 36, and 50% for months 37 through 48. As of December 31, 2023, we had hedged 73% of our available oil and condensate hedge volumes and 66% of our available natural gas hedge volumes for 2024.

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, unrealized gains and losses on commodity derivative instruments, non-cash equity-based compensation, 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.

Adjusted EBITDA and Distributable cash flow should not be considered an alternative to, or more meaningful than, net income (loss), income (loss) from operations, cash flows from operating activities, or any other measure of financial performance presented in accordance with generally accepted accounting principles ("GAAP") in the 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), the most directly comparable GAAP financial measure, to Adjusted EBITDA and Distributable cash flow for the periods indicated:

	Year Ended December 31,	
	2023	2022
	(in thousands)	
Net income (loss)	$ 422,549	$ 476,480
Adjustments to reconcile to Adjusted EBITDA:		
Depreciation, depletion, and amortization	45,683	47,804
Interest expense	2,754	6,286
Income tax expense (benefit)	320	58
Accretion of asset retirement obligations	1,042	861
Equity-based compensation	10,829	17,388
Unrealized (gain) loss on commodity derivative instruments	(8,394)	(82,486)
(Gain) loss on sale of assets, net	(73)	(17)
Adjusted EBITDA	474,710	466,374
Adjustments to reconcile to Distributable cash flow:		
Change in deferred revenue	(9)	(30)
Cash interest expense	(1,715)	(4,282)
Preferred unit distributions	(21,776)	(21,000)
Distributable cash flow	$ 451,210	$ 441,062

Results of Operations

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

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

	Year Ended December 31,			
	2023	2022	Variance	
	(dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	3,757	3,591	166	4.6 %
Natural gas (MMcf)[1]	64,647	59,778	4,869	8.1 %
Equivalents (MBoe)	14,532	13,554	978	7.2 %
Equivalents/day (MBoe)	39.8	37.1	2.7	7.3 %
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 76.74	$ 93.65	$ (16.91)	(18.1)%
Natural gas ($/Mcf)[1]	3.10	7.28	(4.18)	(57.4)%
Equivalents ($/Boe)	$ 33.62	$ 56.90	$ (23.28)	(40.9)%
Revenue:				
Oil and condensate sales	$ 288,296	$ 336,287	$ (47,991)	(14.3)%
Natural gas and natural gas liquids sales[1]	200,297	434,945	(234,648)	(53.9)%
Lease bonus and other income	12,506	13,052	(546)	(4.2)%
Revenue from contracts with customers	501,099	784,284	(283,185)	(36.1)%
Gain (loss) on commodity derivative instruments	91,117	(120,680)	211,797	(175.5)%
Total revenue	$ 592,216	$ 663,604	$ (71,388)	(10.8)%
Operating expenses:				
Lease operating expense	$ 11,386	$ 12,380	$ (994)	(8.0)%
Production costs and ad valorem taxes	56,979	66,233	(9,254)	(14.0)%
Exploration expense	2,148	193	1,955	1013.0 %
Depreciation, depletion, and amortization	45,683	47,804	(2,121)	(4.4)%
General and administrative	51,455	53,652	(2,197)	(4.1)%
Other expense:				
Interest expense	2,754	6,286	(3,532)	(56.2)%

[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, 2023 decreased compared to the year ended December 31, 2022. The decrease in total revenue from the corresponding period is primarily due to lower realized commodity prices partially offset by an increase in production volumes and a gain on commodity derivative instruments in 2023 compared to a loss in 2022.

Oil and condensate sales. Oil and condensate sales for the year ended December 31, 2023 were lower than the corresponding period in 2022 due to lower realized commodity prices partially offset by higher production volumes. The increase in oil and condensate production was primarily due to increased production volumes in the Permian Basin. Our mineral and royalty interest oil and condensate volumes accounted for 94% and 93% of total oil and condensate volumes for each of the years ended December 31, 2023 and 2022, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased for the year ended December 31, 2023 as compared to the year ended December 31, 2022 due to lower realized commodity prices offset by higher production volumes. The increase in natural gas and NGL production was driven by new development in the Haynesville/Bossier play trend, including new activity from the Aethon development program in the Shelby Trough. Mineral and royalty interest production accounted for 94% and 92% of our natural gas volumes for the years ended December 31, 2023 and 2022, 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 2023, we recognized $82.7 million of realized gains and $8.4 million of unrealized gains from our commodity derivatives, compared to $203.2 million of realized losses and $82.5 million of unrealized gains in 2022. The unrealized gains on our commodity contracts in 2023 were primarily driven by changes in the forward commodity price curves for natural gas and in 2022 by changes in the forward commodity price curves for both oil and 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 income 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 slightly lower for the year ended December 31, 2023, as compared to the same period in 2022. Leasing activity in the Haynesville/Bossier and Wolfcamp plays made up the majority of lease bonus and other income in 2023 and 2022.

Operating Expenses

Lease operating expense. Lease operating expense includes recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased in 2023 as compared to 2022, primarily due to a reduction in variable costs as a result of lower production from our non-operated working interest properties.

Production costs and ad valorem taxes. Production taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the regulations of the states where the production originates, these taxes may be based on a percentage of the realized value or a fixed amount per production unit. This category also includes the costs to process and transport our production to applicable sales points. Ad valorem taxes are jurisdictional taxes levied on the value of oil and natural gas minerals and reserves. Rates, methods of calculating property values, and timing of payments vary between taxing authorities. For the year ended December 31, 2023, production and ad valorem taxes decreased as compared to the year ended December 31, 2022, as a result of lower commodity prices.

Exploration expense. Exploration expense typically consists of dry-hole expenses, delay rentals, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense for 2023 significantly increased due to costs incurred to acquire seismic information related to our mineral and royalty interests.

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 such 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, 2023 as compared to 2022, primarily due to a reduction in cost basis with a lower corresponding reduction in proved developed producing reserve quantities. The reduction in cost basis is primarily due to depreciation, depletion, and amortization recorded during the prior twelve months.

General and administrative. General and administrative expenses are costs not directly associated with the production of oil and natural gas and include the cost of employee salaries and related benefits, office expenses, and fees for professional services. For the year ended December 31, 2023, general and administrative expenses decreased compared to 2022, primarily due to a $6.6 million decrease in equity-based compensation from lower costs recognized for performance-based incentive awards resulting from downward movements in our common unit price during 2023 compared to upward movements in our common unit price during 2022. The overall decrease was partially offset by increases in consulting costs of $2.6 million related to internal projects and a non-recurring $2.1 million recovery in allowance against an outstanding long-term receivable in 2022.

Other Expense

Interest expense. For the year ended December 31, 2023, interest expense decreased compared to 2022, primarily due to lower average outstanding borrowings resulting from fully paying down our Credit Facility in the first quarter of 2023. Interest expense in 2023 consisted primarily of commitment fees and amortization of debt issuance costs.

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 as applicable, and for investing in our business. 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 until February 26, 2024 at a redemption price of $21.41 per Series B cumulative convertible preferred unit, which is equal to 105% of par value. Thereafter, we may redeem the preferred units at par value, equal to $20.39, within a 90-day period on each second anniversary following November 28, 2023. 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 our executed farmout agreements and internally generated cash flows, although at times we may fund a portion of these expenditures through other financing sources such as borrowings under our Credit Facility.

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.

Cash Flows

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

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

	Year Ended December 31,		
	2023	**2022**	**Change**
		(in thousands)	
Cash flows provided by operating activities	$ 521,251	$ 424,983	$ 96,268
Cash flows provided by (used in) investing activities	(19,740)	(1,215)	(18,525)
Cash flows provided by (used in) financing activities	(435,536)	(428,337)	(7,199)

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 2023 increased as compared to 2022. The increase was primarily due to an increase in net cash received on settlements of commodity derivative instruments in 2023 compared to net cash paid in the same period of 2022. The overall increase was partially offset by a decrease in oil and condensate sales revenue and natural gas and NGL sales revenue due to lower realized commodity prices.

Investing Activities. Net cash used in investing activities for 2023 increased as compared to 2022. The change was primarily due to increased acquisition activity and higher net oil and natural gas capital expenditures in 2023 compared to the same period in 2022.

Financing Activities. Cash flows used in financing activities for 2023 increased as compared to 2022. The increase was primarily due to higher distributions paid to common unitholders partially offset by lower net repayments under our Credit Facility in 2023 compared with 2022.

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.

Our 2024 capital expenditure budget associated with our non-operated working interests is expected to be approximately $2.3 million. The majority of this capital is anticipated to be spent on workovers and recompletions on existing wells in which we own a working interest.

We spent approximately $4.8 million and $0.6 million associated with our non-operated working interests, net of farmout reimbursements during 2023 and 2022, respectively.

Acquisitions

During the year ended December 31, 2023, we acquired mineral and royalty interests 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 the Gulf Coast land region. Our current commercial strategy includes the continuation of meaningful, targeted mineral and royalty acquisitions to complement our existing positions.

We had no material acquisition activity during 2022.

During 2021 we closed an acquisition of mineral and royalty acreage in the northern Midland Basin for total consideration of $20.8 million. The purchase price consisted of $10.0 million in cash and $10.8 million in common units. The assets acquired consisted of $4.9 million of proved oil and natural gas properties, $15.6 million of unproved oil and natural gas properties, and $0.3 million of net working capital.

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

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. 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. In October 2022, we revised and amended the Credit Facility to extend the maturity date from November 1, 2024 to October 31, 2027, increased the borrowing base to $550.0 million and elected to lower commitments under the Credit Facility to $375.0 million. The April 2023 borrowing base redetermination reaffirmed the borrowing base at $550.0 million and the October 2023 borrowing base redetermination increased the borrowing base to $580.0 million. After both redeterminations we elected to maintain cash commitments at $375.0 million. The next semi-annual redetermination is scheduled for April 2024.

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, 2023, 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.

Contractual Obligations

The following table summarizes our minimum payments as of December 31, 2023 (in thousands):

		Payments due by period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Operating lease obligations	$ 2,463	$ 655	$ 1,764	$ 44	$ —
Purchase commitments	660	450	205	5	—
Total	$ 3,123	$ 1,105	$ 1,969	$ 49	$ —

Critical Accounting Policies and Related 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 oil and natural gas properties. 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.

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

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 $45.0 million, $47.2 million, and $60.4 million for the years ended December 31, 2023, 2022, and 2021, respectively.

We evaluate impairment of producing properties whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. This evaluation is performed on a depletable unit basis. We compare 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 fair value include estimates of proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, and a risk-adjusted discount rate. There was no impairment of proved oil and natural gas properties for the years ended December 31, 2023, 2022, and 2021.

Unproved properties are also assessed for impairment periodically on a depletable unit basis when facts and circumstances indicate that the carrying value may not be recoverable, at which point an impairment loss is recognized to the extent the carrying value 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. There was no impairment of unproved properties for the years ended December 31, 2023, 2022, and 2021.

Upon the sale of a complete depletable unit, the book value thereof, less proceeds or salvage value, is charged to income. 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, 2023 reserve report. Applying this discount results in an approximate 2.0% reduction of estimated proved reserve volumes as compared to the undiscounted pricing scenario used in our December 31, 2023 reserve report prepared by NSAI.

Revenues from Contracts with Customers

Accounting Standards Codification ("ASC") 606, *Revenue from Contracts with Customers*, requires us 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 we receive 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, we recognize revenue from oil and natural gas sales using the practical expedient for variable consideration in ASC 606.

Allocation of transaction price to remaining performance obligations

Oil and natural gas sales

We have utilized the practical expedient in ASC 606 which states we are 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 we have 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.

Prior-period performance obligations

We record oil and natural gas 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 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, we are 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 Accounts receivable line item in the accompanying consolidated balance sheets. The difference between our 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. For the years ended December 31, 2023 and 2022, revenue recognized in the reporting periods related to performance obligations satisfied in prior reporting periods was immaterial.

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 for several years, and we expect this unpredictability to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative 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.

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, 2023. Applying this discount results in an approximate 2.0% reduction of proved reserve volumes as compared to the undiscounted December 31, 2023 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, 2023, we had seven 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 twelve months ended December 31, 2023, we had weighted average outstanding borrowings under our Credit Facility of $3.4 million, bearing interest at a weighted-average interest rate of 7.36%. 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 less than $0.1 million for the year ended December 31, 2023, 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, 2023 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, 2023, 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, 2023.

This Annual Report includes an attestation report of Ernst & Young LLP, our independent registered public accounting firm, on our internal control over financial reporting as of December 31, 2023, which is included in the Annual Report on page F-2.

Changes in Internal Control over Financial Reporting

There were no changes in our system of 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, 2023, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2023, none of our directors or executive officers adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

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 2024 Annual Meeting of Limited Partners ("2024 Proxy Statement"), which will be filed with the SEC not later than 120 days after December 31, 2023.

The following table shows information for the executive officers and directors of the General Partner. Executive officers serve at the discretion of the Board. Directors hold office until their successors are duly elected and qualified. There are no family relationships among any of our directors or executive officers.

Name	Age	Position With The General Partner
Thomas L. Carter, Jr.	72	Chairman, Chief Executive Officer, and President
Evan M. Kiefer	36	Senior Vice President, Chief Financial Officer and Treasurer
L. Steve Putman	48	Senior Vice President, General Counsel, and Secretary
Carrie P. Clark	47	Senior Vice President, Land & Commercial
Dawn K. Smajstrla	53	Vice President and Chief Accounting Officer
Carin M. Barth	61	Director
D. Mark DeWalch	62	Director
Jerry V. Kyle, Jr.	63	Director
Michael C. Linn	72	Director
John H. Longmaid	78	Director
William N. Mathis	57	Director
William E. Randall	57	Director
Alexander D. Stuart	73	Director
James W. Whitehead	48	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 Chief Executive Officer, Chief Financial Officer, Chief 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 from our Financial Code of Ethics, if any, 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 2024 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2023.

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 2024 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2023.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to the 2024 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2023.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Our independent registered public accounting firm is Ernst & Young LLP, Houston TX, Auditor Firm ID: 42.

Information required by this item is incorporated by reference to the 2024 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2023.

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 December 12, 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	Fourth Amended and Restated Credit Agreement, among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P., as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent, Bank of America, N.A. and Compass Bank, as Co-Syndication Agents, ZB Bank, N.A. DBA and Amegy Bank National Association, as Documentation Agent, and the lenders signatory thereto, dated as of November 1, 2017 (incorporated herein by reference to Exhibit 10.1 to Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 7, 2017 (SEC File No. 001-37362)).
10.3	First Amendment to Fourth Amended and Restated Credit Agreement among Black Stone Minerals Company, L.P., as Borrower, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, Bank of America, N.A. and Compass Bank, as Co-Syndication Agents, ZB Bank, N.A., DBA Amegy Bank, National Association, as Documentation Agent, and a syndicate of lenders dated as of February 7, 2018.
10.4	Second Amendment to Fourth Amended and Restated Credit Agreement among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P., as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent, and a syndicate of lenders dated as of October 31, 2018 (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 5, 2018 (SEC File No. 001-37362)).
10.5	Third Amendment to Fourth Amended and Restated Credit Agreement among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P., as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent, and a syndicate of lenders dated as of May 1, 2020.
10.6	Fourth Amendment to Fourth Amended and Restated Credit Agreement among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P., as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent, and a syndicate of lenders dated as of November 3, 2020.
10.7	Fifth Amendment to Fourth Amended and Restated Credit Agreement among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P. as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent, and a syndicate of lenders dated as of April 30, 2021.
10.8	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
10.9^	Form of Non-Employee Director Unit Grant Notice and Award Agreement (incorporated herein by reference to Exhibit 10.11 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on April 13, 2015 (SEC File No. 333-202875)).
10.10^	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)).
10.11^*	Form of Severance Agreement for Senior Vice Presidents
10.12^	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. 333-202875)).
10.13^	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. 333-202875)).
10.14^	Form of STI Award Letter (Leadership) under the Black Stone Minerals, L.P. Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.17 of Black Stone Minerals, L.P.'s Annual Report on Form 10-K filed on February 28, 2018 (SEC File No. 001-37362)).
10.15^	LTI Form of LTI Award Grant Notice and Award Agreement (Performance Cash Award) under the Black Stone Minerals, L.P. Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on May 3, 2022 (SEC File No. 001-37362)).
10.16^	LTI Form of LTI Award Grant Notice and Award Agreement (Performance Equity Award) under the Black Stone Minerals, L.P. Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.2 of Black Stone Minerals, L.P.'s Quarterly Report on Form 10-Q filed on May 3, 2022 (SEC File No. 001-37362)).

10.17	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 December 12, 2017 (SEC File No. 001-37362)).
10.18^	Separation Agreement and General Release of Claims, dated as of March 2, 2023, by and among Jeffrey P. Wood, Black Stone Natural Resources Management Company, and Black Stone Minerals GP, L.L.C. (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on March 3, 2023).
21.1*	List of Subsidiaries of Black Stone Minerals, L.P.
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer and Chief Financial Officer of Black Stone Minerals, L.P. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
97.1*	Black Stone Minerals, L.P. Incentive-Based Compensation Recoupment Policy, adopted as of October 18, 2023.
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 20, 2024

By: /s/ Thomas L. Carter, Jr.
Thomas L. Carter, Jr.
Chief Executive Officer and Chairman

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/ Thomas L. Carter, Jr. Thomas L. Carter, Jr.	President, Chief Executive Officer and Chairman (Principal Executive Officer)	February 20, 2024
/s/ Evan M. Kiefer Evan M. Kiefer	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 20, 2024
/s/ Dawn K. Smajstrla Dawn K. Smajstrla	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 20, 2024
/s/ Carin M. Barth Carin M. Barth	Director	February 20, 2024
/s/ D. Mark DeWalch D. Mark DeWalch	Director	February 20, 2024
/s/ Jerry V. Kyle, Jr. Jerry V. Kyle, Jr.	Director	February 20, 2024
/s/ Michael C. Linn Michael C. Linn	Director	February 20, 2024
/s/ John H. Longmaid John H. Longmaid	Director	February 20, 2024
/s/ William N. Mathis William N. Mathis	Director	February 20, 2024
/s/ William E. Randall William E. Randall	Director	February 20, 2024
/s/ Alexander D. Stuart Alexander D. Stuart	Director	February 20, 2024
/s/ James W. Whitehead James W. Whitehead	Director	February 20, 2024

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

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Black Stone Minerals, L.P. and subsidiaries (the Partnership) as of December 31, 2023 and 2022, the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have 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, 2023, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 20, 2024, expressed an unqualified opinion thereon.

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 Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate 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 consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depreciation, Depletion and Amortization ("DD&A") of Oil and Natural Gas Properties

Description of the Matter	At December 31, 2023, the net book value of the Partnership's oil and natural gas properties was $1,064 million, and depreciation, depletion and amortization ("DD&A") expense related to the Partnership's oil and natural gas properties was $45 million for the year then ended. As discussed in Note 2, the Partnership follows the successful efforts method of accounting for its oil and natural gas properties. DD&A of 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, as determined by independent petroleum engineers. Leasehold acquisition costs and costs to acquire proved properties are amortized on the basis of total proved reserves, also determined by independent petroleum engineers. Proved oil and natural gas 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. Subjective judgment is required by the independent petroleum engineers in interpreting the data used to estimate proved oil and natural gas reserves. Estimating proved oil and natural gas reserves also requires the selection of inputs, including historical production, oil and natural gas price assumptions, future operating costs assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating proved oil and natural gas reserves, management used independent petroleum engineers to determine the proved oil and natural gas reserves estimates as of December 31, 2023.
	Auditing the Partnership's oil and natural gas properties DD&A calculation is especially complex because of the use of the work of the independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in determining proved oil and natural gas reserves.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Partnership's controls over its process to calculate oil and natural gas properties DD&A, including management's controls over the accuracy of the financial data provided to the engineers for use in determining proved oil and natural gas reserves.
	Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the independent petroleum engineers used to determine the proved oil and natural gas reserves estimates. In addition, in assessing whether we can use the work of the independent petroleum engineers we evaluated the accuracy of the financial data and inputs described above used by the engineers in determining proved oil and natural gas reserves by evaluating corroborative and contrary evidence. We also tested the mathematical accuracy of the oil and natural gas properties DD&A calculation, including comparing the proved oil and natural gas reserves amounts used in the calculation to the Partnership's reserves report.

Revenues from Contracts with Customers Accrual

Description of the Matter	At December 31, 2023, the Partnership had $77.6 million in accrued revenues from contracts with customers. As discussed in Note 2, 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 Accounts receivable line item in the consolidated balance sheets. Auditing the Partnership's revenues from contracts with customers accrual is complex and judgmental because it involves the evaluation of subjective management inputs and assumptions used in the calculation. Additionally, auditing the revenues from contracts with customers accrual is challenging because the Partnership's mineral and royalty interests include ownership in a significant amount of producing wells.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Partnership's process to estimate the revenues from contracts with customers accrual, including management's controls over the significant assumptions and completeness and accuracy of the data used in the calculation. Our audit procedures included, among others, testing the significant inputs to the calculation of the revenues from contracts with customers accrual by evaluating corroborative and contrary evidence. These inputs included oil and natural gas price assumptions and production estimates. Additionally, we assessed the historical accuracy of the revenues from contracts with customers accrual through lookback procedures.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2016.
Houston, Texas
February 20, 2024

Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control Over Financial Reporting

We have audited Black Stone Minerals, L.P. and subsidiaries' internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), (the COSO criteria). In our opinion, Black Stone Minerals, L.P. and subsidiaries (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2023 and 2022, the related consolidated statements of operations, equity, and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and our report dated February 20, 2024, expressed an unqualified opinion thereon.

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 partnership'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 partnership'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 partnership; (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 partnership are being made only in accordance with authorizations of management and directors of the partnership; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the partnership'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/ Ernst & Young LLP

Houston, Texas
February 20, 2024

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

	As of December 31,	
	2023	**2022**
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 70,282	$ 4,307
Accounts receivable	82,253	135,697
Commodity derivative assets	38,273	31,472
Prepaid expenses and other current assets	2,319	1,905
TOTAL CURRENT ASSETS	193,127	173,381
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $890,338 and $909,344 at December 31, 2023 and 2022, respectively	3,026,394	3,003,907
Accumulated depreciation, depletion, amortization, and impairment	(1,961,899)	(1,916,919)
Oil and natural gas properties, net	1,064,495	1,086,988
Other property and equipment, net of accumulated depreciation of $14,163 and $13,461 at December 31, 2023 and 2022, respectively	1,007	1,259
NET PROPERTY AND EQUIPMENT	1,065,502	1,088,247
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	8,255	9,454
TOTAL ASSETS	$ 1,266,884	$ 1,271,082
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 6,270	$ 6,773
Accrued liabilities	17,003	19,729
Commodity derivative liabilities	1,229	3,243
Other current liabilities	1,334	989
TOTAL CURRENT LIABILITIES	25,836	30,734
LONG-TERM LIABILITIES		
Credit facility	—	10,000
Accrued incentive compensation	1,699	1,884
Commodity derivative liabilities	81	16
Asset retirement obligations	19,030	15,030
Other long-term liabilities	2,893	3,606
TOTAL LIABILITIES	49,539	61,270
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, 2023 and 2022, respectively	299,137	298,361
EQUITY		
Partners' equity — general partner interest	—	—
Partners' equity — common units, 209,991 and 209,407 units outstanding at December 31, 2023 and 2022, respectively	918,208	911,451
TOTAL EQUITY	918,208	911,451
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,266,884	$ 1,271,082

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,		
	2023	**2022**	**2021**
REVENUE			
Oil and condensate sales	$ 288,296	$ 336,287	$ 235,771
Natural gas and natural gas liquids sales	200,297	434,945	255,671
Lease bonus and other income	12,506	13,052	14,292
Revenue from contracts with customers	501,099	784,284	505,734
Gain (loss) on commodity derivative instruments	91,117	(120,680)	(146,474)
TOTAL REVENUE	592,216	663,604	359,260
OPERATING (INCOME) EXPENSE			
Lease operating expense	11,386	12,380	13,056
Production costs and ad valorem taxes	56,979	66,233	49,809
Exploration expense	2,148	193	1,082
Depreciation, depletion, and amortization	45,683	47,804	61,019
General and administrative	51,455	53,652	48,746
Accretion of asset retirement obligations	1,042	861	1,073
(Gain) loss on sale of assets, net	(73)	(17)	(2,850)
TOTAL OPERATING EXPENSE	168,620	181,106	171,935
INCOME (LOSS) FROM OPERATIONS	423,596	482,498	187,325
OTHER INCOME (EXPENSE)			
Interest and investment income	1,867	53	1
Interest expense	(2,754)	(6,286)	(5,638)
Other income (expense)	(160)	215	299
TOTAL OTHER EXPENSE	(1,047)	(6,018)	(5,338)
NET INCOME (LOSS)	422,549	476,480	181,987
Distributions on Series B cumulative convertible preferred units	(21,776)	(21,000)	(21,000)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 400,773	$ 455,480	$ 160,987
ALLOCATION OF NET INCOME (LOSS):			
General partner interest	$ —	$ —	$ —
Common units	400,773	455,480	160,987
	$ 400,773	$ 455,480	$ 160,987
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:			
Per common unit (basic)	$ 1.91	$ 2.18	$ 0.77
Per common unit (diluted)	$ 1.88	$ 2.12	$ 0.77
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:			
Weighted average common units outstanding (basic)	209,970	209,382	208,181
Weighted average common units outstanding (diluted)	225,105	224,446	208,290

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—common units	Total equity
BALANCE AT DECEMBER 31, 2020	206,749	$ 760,606	$ 760,606
Repurchases of common units	(223)	(1,957)	(1,957)
Issuance of common units for property acquisitions	1,087	10,766	10,766
Restricted units granted, net of forfeitures	1,053	—	—
Equity-based compensation	—	12,932	12,932
Distributions	—	(176,924)	(176,924)
Charges to partners' equity for accrued distribution equivalent rights	—	(1,142)	(1,142)
Distributions on Series B cumulative convertible preferred units	—	(21,000)	(21,000)
Net income (loss)	—	181,987	181,987
BALANCE AT DECEMBER 31, 2021	208,666	765,268	765,268
Repurchases of common units	(262)	(2,991)	(2,991)
Restricted units granted, net of forfeitures	1,003	—	—
Equity-based compensation	—	18,146	18,146
Distributions	—	(322,403)	(322,403)
Charges to partners' equity for accrued distribution equivalent rights	—	(2,049)	(2,049)
Distributions on Series B cumulative convertible preferred units	—	(21,000)	(21,000)
Net income (loss)	—	476,480	476,480
BALANCE AT DECEMBER 31, 2022	209,407	911,451	911,451
Repurchases of common units	(358)	(5,496)	(5,496)
Restricted units granted, net of forfeitures	942	—	—
Equity-based compensation	—	12,525	12,525
Distributions	—	(398,824)	(398,824)
Charges to partners' equity for accrued distribution equivalent rights	—	(2,221)	(2,221)
Distributions on Series B cumulative convertible preferred units	—	(21,776)	(21,776)
Net income (loss)	—	422,549	422,549
BALANCE AT DECEMBER 31, 2023	209,991	$ 918,208	$ 918,208

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,		
	2023	2022	2021
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 422,549	$ 476,480	$ 181,987
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	45,683	47,804	61,019
Accretion of asset retirement obligations	1,042	861	1,073
Amortization of deferred charges	1,039	1,954	1,579
(Gain) loss on commodity derivative instruments	(91,117)	120,680	146,474
Net cash (paid) received on settlement of commodity derivative instruments	82,723	(203,166)	(112,946)
Equity-based compensation	10,829	17,388	12,218
Exploratory dry hole expense	—	—	1,048
(Gain) loss on sale of assets, net	(73)	(17)	(2,850)
Changes in operating assets and liabilities:			
Accounts receivable	53,053	(39,513)	(34,856)
Prepaid expenses and other current assets	(414)	51	(289)
Accounts payable, accrued liabilities, and other	(3,827)	3,012	2,652
Settlement of asset retirement obligations	(236)	(551)	(229)
NET CASH PROVIDED BY OPERATING ACTIVITIES	521,251	424,983	256,880
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisitions of oil and natural gas properties	(14,605)	(149)	(10,043)
Additions to oil and natural gas properties	(4,213)	(11,894)	(4,066)
Additions to oil and natural gas properties leasehold costs	(545)	(32)	(98)
Purchases of other property and equipment	(450)	(488)	(428)
Proceeds from the sale of oil and natural gas properties	73	17	318
Proceeds from farmouts of oil and natural gas properties	—	11,331	—
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	(19,740)	(1,215)	(14,317)
CASH FLOWS FROM FINANCING ACTIVITIES			
Distributions to common unitholders	(398,824)	(322,403)	(176,924)
Distributions to Series B cumulative convertible preferred unitholders	(21,000)	(21,000)	(21,000)
Repurchases of common units	(5,496)	(2,991)	(1,957)
Borrowings under credit facility	64,000	339,000	212,000
Repayments under credit facility	(74,000)	(418,000)	(244,000)
Debt issuance costs and other	(216)	(2,943)	(3,602)
NET CASH (USED IN) PROVIDED BY FINANCING ACTIVITIES	(435,536)	(428,337)	(235,483)
NET CHANGE IN CASH AND CASH EQUIVALENTS	65,975	(4,569)	7,080
Cash and cash equivalents — beginning of the year	4,307	8,876	1,796
Cash and cash equivalents — end of the year	$ 70,282	$ 4,307	$ 8,876
SUPPLEMENTAL DISCLOSURE			
Interest paid	$ 1,736	$ 4,332	$ 4,035

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

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

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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 oil and natural gas properties. 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 result in a reduction in the Partnership’s fair value estimates and 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.

Accounts Receivable

The Partnership’s accounts receivable balance results primarily from operators’ sales of oil and natural gas to their customers. Accounts receivable are recorded at the contractual amounts and do not bear interest. Any concentration of customers 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 accounts receivable:

	December 31,	
	2023	2022
	(in thousands)	
Accounts receivable:		
Revenues from contracts with customers	$ 77,560	$ 129,078
Other	4,693	6,619
Total accounts receivable	$ 82,253	$ 135,697

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 given price risk associated with its operations, the Partnership uses 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.

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 customer base is high and has not experienced significant write-offs in its accounts receivable balances. See "Note 7 – Significant Customers" 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. Acquisitions of proved oil and natural gas properties and working interests are generally considered business combinations and are recorded at their estimated fair value as of the acquisition date. Acquisitions that consist of all or substantially all unproved oil and natural gas properties are generally considered asset acquisitions and are recorded at cost.

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 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 $45.0 million, $47.2 million, and $60.4 million for the years ended December 31, 2023, 2022, and 2021, 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. There was no impairment of proved or unproved oil and natural gas properties for the years ended December 31, 2023, 2022 and 2021. 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. 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 $0.7 million, $0.6 million, and $0.6 million for the years ended December 31, 2023, 2022, and 2021, 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,	
	2023	2022
	(in thousands)	
Accrued liabilities:		
Accrued capital expenditures	$ 5	$ 162
Accrued incentive compensation	8,041	10,050
Accrued property taxes	6,378	7,431
Accrued other	2,579	2,086
Total accrued liabilities	$ 17,003	$ 19,729

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 $1.0 million, $2.0 million, and $1.6 million for the years ended December 31, 2023, 2022, and 2021, 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, 2023 and 2022, 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.

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

Oil and natural gas sales

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.

Prior-period performance obligations

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 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. For the years ended December 31, 2023 and 2022, revenue recognized in the reporting periods related to performance obligations satisfied in prior reporting periods was immaterial.

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, commodity derivative financial instruments, and accounts payable, approximate their fair value at December 31, 2023 and 2022 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 2023, the FASB issued ASU 2023-07, *Improvements to Reportable Segments Disclosures* (*Topic 280*), which updates reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. In addition, the amendments provide new segment disclosure requirements for entities with a single reportable segment. The guidance is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted. The Partnership does not plan to early adopt and expects the new guidance will not have a material impact on the Partnership's consolidated financial statements and related 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 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,	
	2023	2022
	(in thousands)	
Beginning asset retirement obligations	$ 16,019	$ 13,284
Liabilities incurred	174	124
Liabilities settled	(98)	(294)
Accretion expense	1,042	861
Revisions in estimated costs	3,130	2,044
Dispositions	—	—
Ending asset retirement obligations	$ 20,267	$ 16,019
Current asset retirement obligations	$ 1,237	$ 989
Non-current asset retirement obligations	$ 19,030	$ 15,030

NOTE 4 — OIL AND NATURAL GAS PROPERTIES

Divestitures

The Partnership had no material divestiture activity during 2023 and 2022.

In the third quarter of 2021, the Partnership closed on the divestiture of its wholly owned subsidiary, TLW Investments, L.L.C. ("TLW"), effective September 1, 2021 for total proceeds of $0.2 million. TLW holds non-operating working interests and overriding royalty interests primarily located in Oklahoma and Texas. TLW's assets and liabilities consisted of oil and natural gas properties with a net book value of $3.0 million and asset retirement obligations with a book value of $5.7 million at the time of sale. The Partnership recognized a $2.9 million gain associated with the divestiture included in the (Gain) loss on sale of assets, net line item of the consolidated statement of operations for the year ended December 31, 2021.

Acquisitions

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

2023 Acquisitions

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 the Gulf Coast land region.

2022 Acquisitions

The Partnership had no material acquisition activity during 2022.

2021 Acquisitions

In May 2021, the Partnership closed an acquisition of mineral and royalty acreage in the northern Midland Basin for total consideration of $20.8 million. The purchase price consisted of $10.0 million in cash and $10.8 million in common units of the Partnership. The cash consideration was funded with borrowings under the Credit Facility (as defined in Note 8 - Credit Facility) and funds from operating activities. The transaction was accounted for as a business combination with the assets acquired recorded at their estimated fair values as of the acquisition date. The assets acquired consisted of $4.9 million of proved oil and natural gas properties, $15.6 million of unproved oil and natural gas properties, and $0.3 million of net working capital. Acquisition related costs of $0.3 million were expensed and included in the General and administrative line of the consolidated statement of operations for the year ended December 31, 2021.

Farmout Agreements

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

San Augustine Farmout

In March 2021, BSM and XTO reached an agreement to partition jointly owned working interests in the Brent Miller development area in San Augustine County. Under the partition agreement, BSM and XTO exchanged working interests in certain existing and proposed drilling units, resulting in each company holding 100% of the working interests in their respective partitioned units.

In May 2021, BSM and Aethon Energy ("Aethon") entered into an agreement to develop certain of the Partnership's undeveloped acreage in San Augustine County, including the working interests resulting from the partition agreement discussed above. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to BSM's mineral and leasehold acreage in the contract area. The agreement calls for a minimum of five wells to be drilled in the initial program year, which began in the third quarter of 2021, 10 wells to be drilled in the second and third program years, and, thereafter, a minimum of 12 wells per year beginning with the fourth program year. The Partnership's development agreement with Aethon and related drilling commitments covering its San Augustine County acreage is independent of the development agreement and associated commitments covering Angelina County discussed below.

In May 2021, the Partnership entered into a new farmout agreement (the "Canaan Farmout") with Canaan and in December 2021, the Partnership entered into a farmout agreement (the "Azul Farmout") with Azul-SA, LLC ("Azul"). In April 2022, the Partnership amended the Canaan Farmout and entered into a farmout agreement (the "JWM Farmout") with JWM Oil & Gas LLC ("JWM"). These agreements cover all of the Partnership's working interests under active development by Aethon in San Augustine County, Texas and continue for a 10 year period, unless earlier terminated in accordance with the terms of the agreements. Canaan, Azul, and JWM will each earn a percentage of the Partnership's working interest in wells drilled and operated by Aethon within the contract area subject to the agreements. Canaan, Azul, and JWM were obligated to fund the development of wells drilled by Aethon in the initial program year, and thereafter, have certain rights and options to continue funding the Partnership's working interest for the duration of each farmout agreement. The Partnership will receive an overriding royalty interest ("ORRI") before payout and, in most cases, an increased ORRI after payout on all wells drilled under the farmout agreements. As of December 31, 2023, 17 wells had been spud in the contract area subject to the Canaan, Azul, and JWM Farmouts.

The following tables present the working interests each farmout partner will earn within the contract area under the San Augustine farmout agreements:

Brent Miller Area

Farmout Partner	% of Partnership's Working Interest	Maximum % on an 8/8th basis
Canaan	64.0 %	32.0 %
Azul	20.0 %	10.0 %
JWM	16.0 %	8.0 %
Total	100.0 %	50.0 %

Other Areas

Farmout Partner	% of Partnership's Working Interest	Maximum % on an 8/8th basis
Canaan	40.0 %	10.0 %
Azul	50.0 %	12.5 %
JWM	10.0 %	2.5 %
Total	100.0 %	25.0 %

Angelina Farmout

In May 2020, the Partnership entered into a development agreement with Aethon to develop certain portions of the area forfeited by BPX Energy in Angelina County, Texas. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to the Partnership's mineral and leasehold acreage in the contract area. The agreement calls for a minimum of four wells to be drilled in the initial program year, which began in the third quarter of 2020, 10 wells to be drilled in the second program year, and, beginning with the third program year, 15 wells per year beginning thereafter.

In November 2020, the Partnership entered into a new farmout agreement (the "Pivotal Farmout") with Pivotal. The Pivotal Farmout covers the Partnership's share of working interest under active development by Aethon in Angelina County, Texas and continues until April 2028, unless earlier terminated in accordance to the terms of the agreement. Pivotal will earn 100% of the Partnership's working interest (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells drilled and operated by

Aethon within the contract area subject to the agreement. Pivotal was obligated to fund the development of all wells drilled by Aethon in the initial program year and thereafter, Pivotal has certain rights and options to continue funding the Partnership's working interests for the duration of the Pivotal Farmout. Once Pivotal achieves a specified payout for a designated well group, the Partnership will obtain a majority of the original working interest in such well group. As of December 31, 2023, a total of 45 wells have been spud in the contract area subject to the Pivotal Farmout.

Aethon Time-Out

In December 2023, the Partnership received notice that Aethon was exercising the "time-out" provisions under its joint exploration agreements with BSM in Angelina and San Augustine counties in East Texas. When natural gas prices fall below specified thresholds, Aethon may elect to temporarily suspend its drilling obligations for up to nine consecutive months and a maximum of 18 total months in any 48-month period. The current program year under each agreement is paused during the suspension period such that the program year may extend beyond 12 calendar months. Aethon has not previously invoked the time-out provisions under the agreements.

Impairment of Oil and Natural Gas Properties

Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties. When assessing producing properties for impairment, the Partnership compared 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. No impairment of oil and natural gas properties was recognized for the years ended December 31, 2023, 2022, and 2021. 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, 2023 and 2022, 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 statement of operations in the period of the change. All derivative gains and losses from the Partnership's derivative contracts have been recognized in revenue in the Partnership's accompanying consolidated statements of operations. Derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Partnership’s accompanying consolidated balance sheets as of December 31, 2023 and 2022. 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, 2023, the Partnership had seven counterparties, all of which are rated Baa2 or better by Moody’s and 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:

		As of December 31, 2023		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 41,485	$ (3,212)	$ 38,273
Long-term asset	Deferred charges and other long-term assets	498	(126)	372
Total assets		$ 41,983	$ (3,338)	$ 38,645
Liabilities:				
Current liability	Commodity derivative liabilities	$ 4,441	$ (3,212)	$ 1,229
Long-term liability	Commodity derivative liabilities	207	(126)	81
Total liabilities		$ 4,648	$ (3,338)	$ 1,310

		As of December 31, 2022		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 41,648	$ (10,176)	$ 31,472
Long-term asset	Deferred charges and other long-term assets	797	(69)	728
Total assets		$ 42,445	$ (10,245)	$ 32,200
Liabilities:				
Current liability	Commodity derivative liabilities	$ 13,419	$ (10,176)	$ 3,243
Long-term liability	Commodity derivative liabilities	85	(69)	16
Total liabilities		$ 13,504	$ (10,245)	$ 3,259

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

	For the year ended December 31,		
Derivatives not designated as hedging instruments	**2023**	**2022**	**2021**
		(in thousands)	
Beginning fair value of commodity derivative instruments	$ 28,941	$ (53,545)	$ (20,017)
Gain (loss) on oil derivative instruments	3,888	(46,890)	(75,180)
Gain (loss) on natural gas derivative instruments	87,229	(73,790)	(71,294)
Net cash paid (received) on settlements of oil derivative instruments	(2,653)	77,790	66,418
Net cash paid (received) on settlements of natural gas derivative instruments	(80,070)	125,376	46,528
Net change in fair value of commodity derivative instruments	8,394	82,486	(33,528)
Ending fair value of commodity derivative instruments	$ 37,335	$ 28,941	$ (53,545)

The Partnership had the following open derivative contracts for oil as of December 31, 2023:

Period and Type of Contract	Volume (MBbl)	Weighted Average Price (per Bbl)	Range (per Bbl) Low	Range (per Bbl) High
Oil Swap Contracts:				
2023				
Fourth quarter	180	$ 80.80	$ 73.00	$ 89.50
2024				
First quarter	570	71.45	67.00	81.00
Second quarter	570	71.45	67.00	81.00
Third quarter	570	71.45	67.00	81.00
Fourth quarter	570	71.45	67.00	81.00

The Partnership had the following open derivative contracts for natural gas as of December 31, 2023:

Period and Type of Contract	Volume (BBtu)	Weighted Average Price (per MMBtu)	Range (per MMBtu) Low	Range (per MMBtu) High
Natural Gas Swap Contracts:				
2024				
First quarter	10,010	$ 3.57	$ 3.48	$ 3.76
Second quarter	10,010	3.57	3.48	3.76
Third quarter	10,120	3.57	3.48	3.76
Fourth quarter	10,120	3.57	3.48	3.76

The Partnership had the following open derivative contracts for oil subsequent to December 31, 2023:

Period and Type of Contract	Volume (MBbl)	Weighted Average Price (per Bbl)	Range (per Bbl) Low	Range (per Bbl) High
Oil Swap Contracts:				
2025				
First quarter	210	$ 70.50	$ 70.16	$ 70.75
Second quarter	210	70.50	70.16	70.75
Third quarter	210	70.50	70.16	70.75
Fourth quarter	210	70.50	70.16	70.75

The Partnership entered into the following derivative contracts for natural gas subsequent to December 31, 2023:

Period and Type of Contract	Volume (BBtu)	Weighted Average Price (per MMBtu)	Range (per MMBtu)	
			Low	High
Natural Gas Swap Contracts:				
2024				
First quarter	300	$ 3.00	$ 3.00	$ 3.00
Second quarter	455	3.00	3.00	3.00
Third quarter	460	3.00	3.00	3.00
Fourth quarter	460	3.00	3.00	3.00
2025				
First quarter	900	3.65	3.65	3.65
Second quarter	910	3.65	3.65	3.65
Third quarter	920	3.65	3.65	3.65
Fourth quarter	920	3.65	3.65	3.65

NOTE 6 — FAIR VALUE MEASUREMENTS

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

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

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

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

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. There were no transfers into, or out of, the three levels of the fair value hierarchy for the years ended December 31, 2023 and 2022.

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, 2023 and 2022 approximated the fair value due to variable market rates of interest. These debt fair values, which are Level 3 measurements, were estimated based on the Partnership's incremental borrowing rates for similar types of borrowing arrangements, when quoted market prices were not available. The estimated fair values of the Partnership's financial instruments are not necessarily indicative of the amounts that would be realized in a current market exchange.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership estimated the fair value of commodity derivative financial instruments using the market approach via a model that uses inputs that are observable in the market or can be derived from, or corroborated by, observable data. See "Note 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, 2023					
Financial Assets					
Commodity derivative instruments	$ —	$ 41,983	$ —	$ (3,338)	$ 38,645
Financial Liabilities					
Commodity derivative instruments	—	4,648	—	(3,338)	1,310
As of December 31, 2022					
Financial Assets					
Commodity derivative instruments	$ —	$ 42,445	$ —	$ (10,245)	$ 32,200
Financial Liabilities					
Commodity derivative instruments	—	13,504	—	(10,245)	3,259

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

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

The determination of the fair values of proved and unproved properties acquired in business combinations are estimated by discounting projected future cash flows. The factors used to determine fair value include estimates of economic reserves, future operating and development costs, future commodity prices, timing of future production, and a risk-adjusted discount rate. The Partnership has designated these measurements as Level 3. The Partnership's fair value assessments for recent acquisitions are included in Note 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 assessing for impairment. 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 fair value include estimates of proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, and a risk-adjusted discount rate. 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 have been 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, 2023 and 2022. There were no assets measured at fair value on a non-recurring basis, after initial recognition, for the years ended 2023 and 2022.

NOTE 7 — SIGNIFICANT CUSTOMERS

The Partnership leases mineral interests to exploration and production companies and participates in non-operated working interests when economic conditions are favorable. XTO Energy represented approximately 12% and 19% of total oil and natural gas revenue for the years ended December 31, 2022 and 2021, respectively. No customer exceeded 10% of total oil and natural gas revenue for the year ended December 31, 2023.

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

2022, the Partnership revised and amended the Credit Facility to extend the maturity date from November 1, 2024 to October 31, 2027. Concurrent with the Credit Facility amendment, the borrowing base under the Credit Facility was increased to $550.0 million and the Partnership elected to lower commitments under the Credit Facility from $400.0 million to $375.0 million. The April 2023 borrowing base redetermination reaffirmed the borrowing base at $550.0 million and the October 2023 borrowing base redetermination increased the borrowing base to $580.0 million. After both redeterminations the Partnership elected to maintain cash commitments at $375.0 million. The next semi-annual redetermination is scheduled for April 2024.

In October 2022, the Credit Facility was amended to replace the LIBOR rate with the secured overnight financing rate published by the Federal Reserve Bank of New York ("SOFR"). Outstanding borrowings under the Credit Facility bear interest at a floating rate elected by us equal to a base rate (which is a rate per annum equal to the highest of (a) the Prime Rate in effect on such day, (b) the Federal Funds Rate in effect on such day plus 0.50%, and (c) Adjusted Term SOFR for a one month tenor in effect on such day plus 1.00%) or Adjusted Term SOFR, in each case, plus the applicable margin. As of December 31, 2023 and 2022, the alternative base rate margin ranged from 1.50% to 2.50% and the Adjusted Term SOFR margin ranged from 2.50% to 3.50% depending on the borrowings outstanding in relation to the borrowing base.

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 7.36% during the twelve months ended December 31, 2023 and the weighted-average interest rate was 6.92% as of December 31, 2022. 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 agreement (including the failure to satisfy one of the financial covenants), if the availability under the Credit Facility is less than 10% of the lenders' commitments, or if total debt to EBITDAX is greater than 3.0. As of December 31, 2023, the Partnership was in compliance with all financial covenants in the Credit Facility.

At December 31, 2023, there was no aggregate principal balance outstanding and the aggregate principal balance outstanding at December 31, 2022 was $10.0 million. The unused portion of the available borrowings under the Credit Facility were $375.0 million and $365.0 million at December 31, 2023 and 2022, respectively.

NOTE 9 — INCENTIVE COMPENSATION

Overview

The board of directors of the Partnership’s general partner (the "Board") 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 are eligible to receive awards with respect to the Partnership’s common units. The 2015 LTIP permits 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 are based on a predetermined schedule as approved by the Board or a committee thereof.

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 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 of the Board (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 2023 grant includes restricted common units subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through January 7, 2026. In January of each year, non-employee directors of the Partnership's general partner receive compensation under the 2015 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, 2023.

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2022	823,278	$ 10.72
Granted	284,772	16.03
Vested	(400,139)	10.40
Forfeited	(110,736)	11.18
Unvested at December 31, 2023	597,175	13.38

The weighted-average grant-date fair value per unit for unit-based awards was $16.03, $12.00, and $9.25 for the years ended December 31, 2023, 2022, and 2021, respectively. As of December 31, 2023, unrecognized compensation cost associated with restricted unit awards was $4.3 million, which the Partnership expects to recognize over a weighted-average period of 1.72 years. The fair value of units vested for the years ended December 31, 2023, 2022, and 2021 was $6.2 million, $4.0 million, and $2.3 million, respectively. There were no cash payments made for vested units during the years ended December 31, 2023, 2022, and 2021.

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, 2023.

Performance units	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2022	1,175,529	$ 10.40
Granted[1]	376,832	14.54
Vested	(520,574)	9.98
Forfeited	(109,748)	11.20
Unvested at December 31, 2023	922,039	12.24

[1] Includes 92,060 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 $14.54, $12.40, and $9.61 for the years ended December 31, 2023, 2022, and 2021, respectively. Unrecognized compensation cost associated with performance unit awards was $4.9 million as of December 31, 2023, which the Partnership expects to recognize over a weighted-average period of 1.64 years. The fair value of performance units vested for the years ended December 31, 2023, 2022 and 2021 was $8.0 million, $3.9 million and $2.8 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 include performance cash awards and performance equity awards in the form of restricted performance units. To the extent earned, each performance unit represents the right to receive one common unit. The performance cash awards and performance units are eligible to become earned at the end of the requisite service period on December 31, 2025 if the minimum performance metrics are achieved. The minimum performance metrics are at least 42 Mboe per day of average daily royalty production in either the fourth quarter or the month of December of 2025 while maintaining a net debt to EBITDA ratio less than or equal to 1.0 on December 31, 2025. Average daily royalty production does not include production attributable to acquisitions consummated during the performance period.

The following table summarizes information about the aspirational performance units for the year ended December 31, 2023.

Aspirational Performance units	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2022	1,412,008	$ 11.58
Granted	123,308	16.62
Vested	—	—
Forfeited	(261,803)	11.63
Unvested at December 31, 2023	1,273,513	12.06

Total compensation expense to be recognized over the life of the Aspirational Awards consists of $5.8 million for the performance cash awards and $15.4 million for the performance equity awards. Compensation expense related to the Aspirational Awards will be recorded over the service period when achievement of the performance condition is probable. As of December 31, 2023, the Partnership determined achievement of the performance condition was not yet probable and no expense was recognized.

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, 2023, 2022, and 2021.

Incentive compensation expense	Year Ended December 31, 2023	2022	2021
	(in thousands)		
Cash — short and long-term incentive plan	$ 4,442	$ 7,095	$ 6,824
Equity-based compensation — restricted common units	3,852	4,089	4,146
Equity-based compensation — restricted performance units	4,774	11,174	6,320
Board of Directors incentive plan	2,203	2,125	1,752
Total incentive compensation expense	$ 15,271	$ 24,483	$ 19,042

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 $0.6 million, $0.6 million, and $0.5 million for the years ended December 31, 2023, 2022, and 2021, 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 significant to the consolidated financial statements and no provision for potential remediation costs has been recorded.

Litigation

From time to time, the Partnership is involved in legal actions and claims arising in the ordinary course of business. The Partnership believes existing claims as of December 31, 2023 will be resolved without material adverse effect on the Partnership's financial condition or results of 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 to the Purchaser for a cash purchase price of $20.39 per Series B cumulative convertible preferred unit, resulting in total proceeds of approximately $300 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"). On November 28, 2023, the Distribution

Rate was adjusted to 9.8% and will be readjusting 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 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 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 until February 26, 2024 at a redemption price of $21.41 per Series B cumulative convertible preferred unit, which is equal to 105% of par value. Thereafter, the Partnership may redeem the Series B cumulative convertible preferred units at par within a 90-day period on each second anniversary following November 28, 2023.

The Series B cumulative convertible preferred units had a carrying value of $299.1 million, including accrued distributions of $6.0 million, as of December 31, 2023 and a carrying value of $298.4 million, including accrued distributions of $5.3 million as of December 31, 2022. 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,		
	2023	2022	2021
	(in thousands, except per unit amounts)		
NET INCOME (LOSS)	$ 422,549	$ 476,480	$ 181,987
Distributions on Series B cumulative convertible preferred units	(21,776)	(21,000)	(21,000)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 400,773	$ 455,480	$ 160,987
ALLOCATION OF NET INCOME (LOSS):			
General partner interest	$ —	$ —	$ —
Common units	400,773	455,480	160,987
	$ 400,773	$ 455,480	$ 160,987
NUMERATOR:			
Numerator for basic EPU - Net income (loss) attributable to common unitholders	$ 400,773	$ 455,480	$ 160,987
Effect of dilutive securities	21,776	21,000	—
Numerator for diluted EPU - net income (loss) attributable to common unitholders after the effect of dilutive securities	$ 422,549	$ 476,480	$ 160,987
DENOMINATOR:			
Denominator for basic EPU - weighted average common units outstanding (basic)	209,970	209,382	208,181
Effect of dilutive securities	15,135	15,064	109
Denominator for diluted EPU - weighted average number of common units outstanding after the effect of dilutive securities	225,105	224,446	208,290
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:			
Per common unit (basic)	$ 1.91	$ 2.18	$ 0.77
Per common unit (diluted)	1.88	2.12	0.77

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,		
	2023	2022	2021
	(in thousands)		
Potentially dilutive securities (common units):			
Series B cumulative convertible preferred units on an as-converted basis	—	—	14,968

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, adjusted to 9.8% effective November 28, 2023 and subject to readjustment every two years thereafter; and
- *second*, to the holders of common units.

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

	Year Ended December 31,		
	2023	2022	2021
Distributions declared and paid per common unit	$ 1.90	$ 1.54	$ 0.85

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, 2023. 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 January 31, 2024, the Board approved a distribution for the period from October 1, 2023 to December 31, 2023 of $0.475 per common unit. Distributions will be paid on February 23, 2024 to unitholders of record at the close of business on February 16, 2024.

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,		
	2023	2022	2021
	(in thousands)		
Acquisition Costs of Properties[1]:			
Proved	$ —	$ —	$ 4,965
Unproved	14,605	149	15,559
Exploration Costs	—	—	1,049
Development Costs[1]	4,601	11,293	3,964
Total	$ 19,206	$ 11,442	$ 25,537

[1] Unproved properties include purchases of leasehold prospects. Development costs include costs incurred on farmout wells subject to reimbursement under the Partnership's farmout agreements. See "Note 4 – Oil and Natural Gas Properties" for additional information.

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,	
	2023	2022
	(in thousands)	
Proved properties	$ 2,136,056	$ 2,094,563
Unproved properties	890,338	909,344
Total	3,026,394	3,003,907
Accumulated depreciation, depletion, amortization, and impairment	(1,961,899)	(1,916,919)
Oil and natural gas properties, net	$ 1,064,495	$ 1,086,988

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 $78.21, $94.14, and $66.55 per barrel as of December 31, 2023, 2022, and 2021, 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 $2.64, $6.36, and $3.60 per MMBtu as of December 31, 2023, 2022, and 2021, 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 $76.90 per barrel for oil and $2.63 per Mcf for natural gas as of December 31, 2023, $92.01 per barrel for oil and $6.50 per Mcf for natural gas as of December 31, 2022, and $63.17 per barrel for oil and $3.37 per Mcf for natural gas as of December 31, 2021.

	Crude Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)
Net proved reserves at December 31, 2020	15,952	240,211	55,987
Revisions of previous estimates [1]	4,817	38,537	11,240
Purchases of minerals in place[2]	272	216	308
Sales of minerals in place[4]	(135)	(6,194)	(1,167)
Extensions, discoveries and other additions[3]	1,911	32,592	7,343
Production	(3,646)	(61,445)	(13,886)
Net proved reserves at December 31, 2021	19,171	243,917	59,824
Revisions of previous estimates[1]	1,422	6,455	2,498
Extensions, discoveries and other additions[3]	2,182	78,992	15,347
Production	(3,591)	(59,778)	(13,554)
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[3]	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
Net Proved Developed Reserves			
December 31, 2021	19,111	224,222	56,481
December 31, 2022	19,184	236,529	58,606
December 31, 2023	19,091	228,061	57,101
Net Proved Undeveloped Reserves			
December 31, 2021	60	19,695	3,343
December 31, 2022	—	33,057	5,509
December 31, 2023	—	44,235	7,373

[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 the acquisition of mineral and royalty reserves. In 2021 these were primarily in the Permian Basin.

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

[4] Includes divestitures of mineral and royalty reserves. In 2021 these were primarily in the Anadarko Basin.

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 future income tax expenses deducted from future production revenues in the calculation of the standardized measure because the Partnership is not subject to federal income taxes. The Partnership is subject to certain state based taxes; however, these amounts are not material. See "Note 2 – Summary of Significant Accounting Policies" for additional information.

	Year Ended December 31,		
	2023	2022	2021
	(in thousands)		
Future cash inflows	$ 2,184,038	$ 3,518,494	$ 2,033,256
Future production costs	(211,826)	(339,603)	(206,785)
Future development costs	(61,723)	(49,081)	(43,500)
Future income tax expense	(6,259)	(10,535)	(6,322)
Future net cash flows (undiscounted)	1,904,230	3,119,275	1,776,649
Annual discount 10% for estimated timing	(884,720)	(1,454,264)	(804,527)
Total	$ 1,019,510	$ 1,665,011	$ 972,122

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

	Year Ended December 31,		
	2023	2022	2021
	(in thousands)		
Standardized measure, beginning of year	$ 1,665,011	$ 972,122	$ 493,497
Sales, net of production costs	(420,228)	(692,629)	(428,577)
Net changes in prices and production costs related to future production	(649,695)	773,189	537,659
Extensions, discoveries and improved recovery, net of future production and development costs	295,413	476,342	148,732
Previously estimated development costs incurred during the period	—	854	245
Revisions of estimated future development costs	(4,221)	(1,986)	2,254
Revisions of previous quantity estimates, net of related costs	(78,139)	68,270	210,039
Accretion of discount	167,064	97,553	49,530
Purchases of reserves in place, less related costs	—	—	9,254
Sales of reserves in place	—	—	(1,037)
Changes in timing and other	44,305	(28,704)	(49,474)
Net increase (decrease) in standardized measures	(645,501)	692,889	478,625
Standardized measure, end of year	$ 1,019,510	$ 1,665,011	$ 972,122

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.

SEVERANCE AGREEMENT

This Severance Agreement (this "Agreement") is made by and between Black Stone Natural Resources Management Company, a Delaware corporation (the "Company"), and *[Executive]* ("Executive"), effective as of *[Effective Date]* (the "Effective Date"). The Company and Executive are referred to individually herein as a "Party" and collectively as the "Parties."

W I T N E S S E T H:

WHEREAS, the Company acknowledges that Executive possesses skills and knowledge that are valuable to the Company and the Company wishes to enter this Agreement in order to better ensure itself of access to the continued services of Executive, to provide further incentive for Executive to build and preserve the goodwill of the Company, and in order to protect its legitimate business interests, including the preservation of its goodwill and Confidential Information (as defined below); and

WHEREAS, Executive wishes to continue in employment with the Company, advance the business interests of the Company and obtain the benefits set forth herein.

NOW, THEREFORE, for and in consideration of the mutual promises, covenants and obligations contained herein, the Company and Executive agree as follows:

Article I
DEFINITIONS

In addition to the terms defined in the body of this Agreement, for purposes of this Agreement, the following capitalized words shall have the meanings indicated below:

1.1 "Affiliates" means with respect to any person, any other Person that directly or indirectly through one or more intermediaries controls, is controlled by or is under common control with, the Person in question. As used herein, the term "control" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

1.2 "Board" means the board of directors of the General Partner.

1.3 "Business" means the business and operations that are the same or similar to those engaged in by the Company and any of its Affiliates for which Executive provides services during Executive's employment with the Company or any of its Affiliates, or in which the Company or any such Affiliate has material plans to engage of which Executive is aware during the period of his employment with the Company, which business and operations include the business of owning, acquiring, leasing and developing private fee mineral assets and royalty interests.

1.4 "Cause" means a determination by two-thirds of the Board that Executive has: (a) willfully and continually failed to substantially perform Executive's duties to the Company and its Affiliates (other than a failure resulting from Executive's incapacity due to physical or mental illness); (b) willfully engaged in conduct that is demonstrably and materially injurious to the Company, the Partnership, the General Partner or any of their respective Affiliates, monetarily or otherwise; (c) been convicted of, or has plead guilty or *nolo contendere* to, a misdemeanor involving moral turpitude or a felony; (d) committed an act of fraud, or material embezzlement or material theft, in each case, in the course of Executive's employment relationship with the Company or one of its Affiliates; or (e) materially breached any obligations of Executive under this Agreement or any other written agreement entered into between Executive and the

Company, the Partnership, the General Partner or any of their respective Affiliates. Notwithstanding the foregoing, except for a failure, breach or refusal that, by its nature, cannot reasonably be expected to be cured, Executive shall have 30 days following the delivery of written notice by the Company or one of its Affiliates within which to cure any actions or omissions described in clauses (a), (b), (d) or (e) constituting Cause; *provided, however*, that, if the Company reasonably expects irreparable injury from a delay of 30 days, the Company or one of its Affiliates may give Executive notice of such shorter period within which to cure as is reasonable under the circumstances, which may include the termination of Executive's employment without notice and with immediate effect.

1.5 "Change in Control" has the meaning assigned to such term in the LTIP.

1.6 "CIC Protection Period" means the 24-month period beginning on the date a Change in Control occurs.

1.7 "Code" means the Internal Revenue Code of 1986, as amended, and applicable administrative guidance issued thereunder.

1.8 "Date of Termination" means the effective date of the termination of Executive's employment with the Company and its Affiliates, as applicable, such that Executive is no longer employed by the Company or any of its Affiliates.

1.9 "Disability" means Executive's inability to perform the essential functions of Executive's position with the Company or its Affiliate, with reasonable accommodation, for a period of at least 90 consecutive days or 120 days in any 12-month period.

1.10 "General Partner" means Black Stone Minerals GP, L.L.C., a Delaware limited liability company.

1.11 "Good Reason" means the occurrence of any of the following events without Executive's written consent: (a) a reduction in Executive's total compensation other than a general reduction in compensation that affects all similarly situated employees in substantially the same proportions; (b) a relocation of Executive's principal place of employment by more than 50 miles from the location of Executive's principal place of employment as of the Effective Date; (c) any material breach of this Agreement by the Company or any breach by the Company, the Partnership, the General Partner or any of their respective Affiliates of any other written agreement with Executive; (d) a material, adverse change in Executive's title, authority, duties or responsibilities (other than while Executive is physically or mentally incapacitated or as required by applicable law); (e) a material adverse change in the reporting structure applicable to Executive; or (f) following a Change in Control, either (i) a failure of the Company or one of its Affiliates to continue in effect any benefit plan or compensation arrangement in which Executive was participating immediately prior to such Change in Control or (ii) the taking of any action by the Company or one of its Affiliates that adversely affects Executive's participation in, or materially reduces Executive's benefits or compensation under, any such benefit plan or compensation arrangement, unless, in the case of either clause (i) or (ii), there is substituted a comparable benefit plan or compensation arrangement that is at least economically equivalent to the benefit plan or compensation arrangement being terminated or in which Executive's participation is being adversely affected or Executive's benefits or compensation are being materially reduced. Notwithstanding the foregoing provisions of this definition or any other provision of this Agreement to the contrary, any assertion by Executive of a termination for Good Reason shall not be effective unless all of the following conditions are satisfied: (1) Executive must provide written notice to the Company of the existence of the condition(s) providing grounds for termination for Good Reason within 30 days of the initial existence of such grounds; (2) the condition(s) specified in such notice must remain uncorrected for 30 days following the Company's receipt of such written notice; and (3) the date of Executive's termination of employment must occur within 60 days after the initial existence of the condition(s) specified in such notice.

1.12 "LTIP" means the Black Stone Minerals, L.P. Long-Term Incentive Plan.

1.13 "Partnership" means Black Stone Minerals, L.P., a Delaware limited partnership.

1.14 "Person" means an individual or a corporation, limited liability company, partnership, joint venture, trust, unincorporated organization, association, governmental agency or political subdivision thereof or other entity.

1.15 "Prohibited Period" means the period during which Executive is employed by the Company or any of its Affiliates and continuing until the date that is 12 months following the Date of Termination.

1.16 "Qualifying Termination" means any termination of Executive's employment (a) by the Company without Cause, or (b) due to Executive's resignation for Good Reason.

1.17 "Release" means a general release of claims, in a form acceptable to the Company, that releases and discharges the Company and each of its Affiliates and their respective affiliates, predecessors, successors, subsidiaries and benefit plans, and the foregoing entities' respective equity holders, officers, directors, managers, members, partners, employees, agents, representatives and other affiliated persons from any and all claims or causes of action or any kind or character, including but not limited to all claims or causes of action arising out of Executive's employment or the termination of such employment.

1.18 "Release Expiration Date" means the date that is 21 days following the date upon which the Company delivers the Release to Executive (which shall occur no later than seven days following the Date of Termination) or, in the event that such termination of employment is "in connection with an exit incentive or other employment termination program" (as such phrase is defined in the Age Discrimination in Employment Act of 1967, as amended), the date that is 45 days following such delivery date.

1.19 "Restricted Area" means the geographic area where the Company or its Affiliates conduct the Business, which area includes the counties and parishes within the following states in which the Company or its Affiliates develop, own or obtain private fee mineral assets or royalty interests: Texas, Mississippi, Alabama, Arkansas, North Dakota, Florida, Nevada, Louisiana and Oklahoma. For the avoidance of doubt, the Restricted Area expressly includes the following parishes within the state of Louisiana: Acadia, Allen, Assumption, Avoyelles, Beauregard, Bienville, Bossier, Caddo, Calcasieu, Caldwell, Catahoula, Claiborne, Concordia, De Soto, East Baton Rouge, East Carroll, Evangeline, Franklin, Grant, Iberville, Jackson, Jefferson Davis, La Salle, Lafayette, Lafourche, Lincoln, Livingston, Madison, Morehouse, Natchitoches, Ouachita, Plaquemines, Pointe Coupee, Rapides, Red River, Richland, Sabine, St. Charles, St. Helena, St. James, St. Landry, St. Mary, Tangipahoa, Tensas, Terrebonne, Union, Vermillion, Vernon, Washington, Webster, and Winn.

1.20 "Severance Payment" means a total amount equal to (a) the product of (i) 1.0 (or, if such termination occurs during the CIC Protection Period, 2.0) and (ii) the sum of Executive's base salary as in effect on *[Compensation Determination Date]* and Executive's target bonus as of *[Compensation Determination Date]*, plus (b) Executive's pro-rata adjusted target bonus for the calendar year that includes the Date of Termination, determined by multiplying Executive's target bonus as of *[Compensation Determination Date]* by a fraction, the numerator of which is the number of days Executive was employed by the Company in the calendar year that includes the Date of Termination and the denominator of which is the number of days in such calendar year, plus (c) any earned but unpaid bonus for the calendar year preceding the calendar year that includes the Date of Termination, payable on or before March 15 of the calendar year following the calendar year in which the Date of Termination occurs.

Article II
SEVERANCE PAYMENTS

1.1 **Severance-Triggering Events**. In the event that Executive's employment with the Company and, as applicable, each of its Affiliates ends due to a Qualifying Termination, then so long as the requirements of Section 2.3 are satisfied and Executive abides by Executive's continuing obligations under Articles III, IV and V:

(a) The Company shall pay the Severance Payment to Executive in accordance with Section 2.2; and

(b) If Executive timely and properly elects to continue coverage for Executive and Executive's spouse and eligible dependents, if any, under the Company's group health plans pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended ("COBRA"), similar in the amounts and types of coverage provided by the Company to Executive prior to the Date of Termination, then for a period of 12 (or, if such termination occurs during the CIC Protection Period, 24) months following the Date of Termination or such earlier date as provided in this Section 2.1(b), the Company shall promptly reimburse Executive on a monthly basis for the entire amount Executive pays to effect and continue such coverage; *provided, however*, that Executive's rights to such reimbursements under this Section 2.1(b) shall terminate at the time Executive becomes eligible to be covered under a group health plan sponsored by another employer (and Executive shall immediately notify the Company in the event that Executive becomes so eligible). Notwithstanding anything in the preceding provisions of this Section 2.1(b) to the contrary, (i) the election of COBRA continuation coverage and the payment of any premiums due with respect to such COBRA continuation coverage will remain Executive's sole responsibility, and the Company will assume no obligation for payment of any such premiums relating to such COBRA continuation coverage and (ii) if the provision of the benefit described in this Section 2.1(b) cannot be provided in the manner described above without penalty, tax or other adverse impact on the Company, then the Company and Executive shall negotiate in good faith to determine an alternative manner in which the Company may provide a substantially equivalent benefit to Executive without such adverse impact on the Company. If (1) Executive's termination of employment pursuant to this Section 2.1 occurs within the CIC Protection Period and (2) Executive has not become eligible to be covered under a group health plan sponsored by another employer prior to the date that is 18 months after the Date of Termination (such date being the "COBRA Payment Trigger Date"), then, on the Company's first regularly scheduled pay date following the COBRA Payment Trigger Date, the Company shall pay to Executive a lump sum cash payment equal to six times the amount Executive paid to effect and continue coverage for Executive and Executive's spouse and eligible dependents, if any, under the Company's group health plan for the full calendar month next preceding the COBRA Payment Trigger Date.

1.2 **Payment of Severance Payment**. The Severance Payment will be paid in a single lump sum cash payment after the date that is 60 days after the Date of Termination, but in no event later than the date that is 70 days after the Date of Termination.

1.3 **Release**. As a condition to the receipt of the Severance Payment and the reimbursement payments contemplated in Section 2.1(b) (and any portion thereof), (a) Executive must execute and deliver the Release to the Company on or before the Release Expiration Date and (b) any revocation period under the Release shall have fully expired without revocation of the Release by Executive.

1.4 **Parachute Taxes in Connection with a Change in Control**. Notwithstanding anything to the contrary in this Agreement, if Executive is a "disqualified individual" (as defined in section 280G(c) of the Code), and the payments and benefits provided for in this Agreement, together with any other payments and benefits which Executive has the right to receive from the Company or any of its Affiliates, would constitute a "parachute payment" (as defined in section 280G(b)(2) of the Code), then the payments and benefits provided for in this Agreement shall be either (a) reduced (but not below zero) so that the present value of such total amounts and benefits received by Executive from the Company and its Affiliates will be one dollar ($1.00) less than three times Executive's "base amount" (as defined in section 280G(b)(3) of the Code) and so that no portion of such amounts and benefits received by Executive shall be subject to the excise tax imposed by section 4999 of the Code or (b) paid in full, whichever produces the better net after-tax position to Executive (taking into account any applicable excise tax under section 4999 of the Code and any other applicable taxes). The reduction of payments and benefits hereunder, if applicable, shall be made by reducing, first, payments or benefits to be paid in cash hereunder in the order in which such payment or benefit would be paid or provided (beginning with such payment or benefit that would be made last in time and continuing, to the extent necessary, through to such payment or benefit that would be made first in time) and, then, reducing any benefit to be provided in-kind hereunder in a similar order. The determination as to whether any such reduction in the amount of the payments and benefits provided hereunder is necessary shall be made by the Company in good faith. If a reduced payment or benefit is made or provided and through error or otherwise that payment or benefit, when aggregated with other payments and benefits from the Company (or its Affiliates) used in determining if a "parachute payment" exists, exceeds one dollar ($1.00) less than three times Executive's base amount, then Executive shall immediately repay such excess to the Company upon notification that an overpayment has been made. Nothing in this Section 2.4 shall require the Company to be responsible for, or have any liability or obligation with respect to, Executive's excise tax liabilities under section 4999 of the Code.

Article III
PROTECTION OF INFORMATION

1.1 **Disclosure to and Property of the Company**. For purposes of this Article III, (a) the term "Company" shall include the Company and each of its Affiliates and (b) the term "Confidential Information" shall mean any and all confidential or proprietary information and materials, as well as all trade secrets, belonging to the Company or other third parties who furnished such information, materials, and/or trade secrets to the Company with an expectation of confidentiality. Confidential Information includes, regardless of whether such information or materials are expressly identified or marked as confidential or proprietary, and whether or not patentable: (1) technical information and materials of the Company or other third parties; (2) business information and materials of the Company or other third parties; (3) any information or material that gives the Company an advantage with respect to its competitors by virtue of not being known by those competitors; and (4) other valuable, confidential information and materials and/or trade secrets of the Company or other third parties. All Confidential Information shall be the sole and exclusive property of the Company. Upon termination of Executive's employment with the Company, for any reason, Executive shall promptly deliver all documents and materials (including electronically stored information) containing or reflecting Confidential Information, and all copies thereof, to the Company. Notwithstanding the preceding provisions of this Section 3.1, the term Confidential Information does not include (i) any information that, at the time of disclosure by the Company, is available to the public other than as a result of any unauthorized act of Executive, or (ii) any information that becomes available to Executive on a non-confidential basis from a source other than the Company or any of its respective directors, officers, employees, agents or advisors; *provided*, that such source is not known by Executive to be bound by a confidentiality agreement with or other obligation of secrecy to the Company regarding the information.

1.2 **Disclosure to Executive**. Executive expressly acknowledges and agrees that Executive has obtained Confidential Information during the course of Executive's employment with the Company and the Parties acknowledge and agree that Executive will be provided with additional Confidential Information in the course of Executive's continued employment with the Company.

1.3 **No Unauthorized Use or Disclosure**. Executive agrees to preserve and protect the confidentiality of all Confidential Information. Executive agrees that Executive will not, at any time during the term of Executive's employment or thereafter, make any unauthorized disclosure of Confidential Information, or make any use thereof, except, in each case, in the carrying out of Executive's responsibilities to the Company. Executive expressly acknowledges and agrees that Executive would violate the terms of this Article III if Executive breaches any of the provisions of Article V below. Executive shall use commercially reasonable efforts to cause all persons or entities to whom any Confidential Information shall be disclosed by Executive hereunder to preserve and protect the confidentiality of such Confidential Information. Executive shall have no obligation hereunder to keep confidential any Confidential Information if and to the extent disclosure thereof is specifically required by applicable Legal Requirements; *provided, however*, that in the event disclosure is required by applicable Legal Requirements and Executive is making such disclosure, Executive shall provide the Company with prompt notice of such requirement prior to making any such disclosure, so that the Company may seek an appropriate protective order.

Article IV
STATEMENTS CONCERNING THE COMPANY AND EXECUTIVE

1.1 **Statements Concerning the Company**. Executive shall refrain, both during and after the termination of the employment relationship, from publishing any oral or written statements about the Company, any of its Affiliates or any of the Company's or such Affiliates' directors, officers, employees, consultants, agents or representatives that (a) are slanderous, libelous or defamatory, (b) disclose confidential information of or regarding the Company, any of its Affiliates or any of its Affiliates' business affairs, directors, officers, managers, members, employees, consultants, agents or representatives, or (c) place the Company, any of its Affiliates, or any of the Company's or any such Affiliates' directors, officers, managers, members, employees, consultants, agents or representatives in a false light before the public. A violation or threatened violation of this prohibition may be enjoined by the courts. The rights afforded the Company and its Affiliates under this provision are in addition to any and all rights and remedies otherwise afforded by law.

1.2 **Statements Concerning Executive**. The Company shall cause its directors, executive officers and human resource representatives to refrain, both during and after the termination of the employment relationship, from publishing any oral or written statements about Executive, any of Executive's Affiliates or any of such Affiliates' directors, officers, employees, consultants, agents or representatives that (a) are slanderous, libelous or defamatory, (b) disclose confidential information of Executive, or (c) place Executive in a false light before the public. A violation or threatened violation of this prohibition may be enjoined by the courts. The rights afforded Executive under this provision are in addition to any and all rights and remedies otherwise afforded by law.

Article V
NON-COMPETITION; NON-SOLICITATION

1.1 **Definitions**. For purposes of this Article V, the term "Company" shall include the Company and each of its Affiliates (a) for which Executive provides services during the period in which Executive is employed by the Company or any of its Affiliates or (b) about which Executive obtains, or has obtained, Confidential Information.

1.2 **Non-Competition; Non-Solicitation**. Executive and the Company agree to the non-competition and non-solicitation provisions of this Article V (i) to protect the trade secrets and Confidential Information of the Company disclosed or entrusted to Executive by the Company or created or developed by Executive for the Company and the business opportunities disclosed or entrusted to Executive by the Company and so as to enforce Executive's obligations not to misuse or disclose the Company's Confidential Information, (ii) to protect the business goodwill of the Company and (iii) as an express incentive for the Company to continue to employ Executive, enter into this Agreement and to provide the benefits herein.

(a) Executive expressly covenants and agrees that during the Prohibited Period, other than on behalf of the Company, Executive will refrain from carrying on or engaging, directly or indirectly, in the Business in the Restricted Area and, accordingly, Executive will not, directly or indirectly within the Restricted Area during the Prohibited Period (other than on behalf of the Company), own, manage, operate, join, become an employee, independent contractor, consultant or advisor of, or otherwise provide services to, control or participate in any business, individual, partnership, firm, corporation or other entity which carries on the Business.

(b) Executive further covenants and agrees that during the Prohibited Period, Executive will not: (i) engage or employ, or solicit or contact with a view to the engagement or employment of, any person who is an officer or employee of the Company; or (ii) canvass, solicit, approach or entice away or cause to be canvassed, solicited, approached or enticed away from the Company any of the Company's customers or suppliers with whom or which Executive had contact on behalf of the Company during the 12 months that precede the Date of Termination or any of the Company's customers, prospective customers, suppliers or prospective suppliers about whom or which Executive received or learned of any Confidential Information during the 12 months that precede the Date of Termination.

1.3 **Relief**. Executive and the Company agree and acknowledge that the limitations as to time, geographical area and scope of activity to be restrained as set forth in Article V of this Agreement are reasonable in all respects and do not impose any greater restraint than is necessary to protect the legitimate business interests of the Company, including the protection of its Confidential Information, trade secrets and goodwill. Executive further acknowledges that the Company conducts business throughout the Restricted Area. Executive and the Company also acknowledge that money damages would not be a sufficient remedy for any breach of this Article V or Articles III or IV above by Executive, and the Company shall be entitled to enforce the provisions of this Article V and Articles III and IV above by terminating payments or additional benefits then owing to Executive and to specific performance, injunctive relief and other equitable relief, without bond, as remedies for such breach or any threatened breach. In addition, in the event of a breach by Executive, Executive will repay to the Company any and all payments received or paid or deemed paid by the Company for the benefit of Executive pursuant to Article II above. Such remedies shall not be deemed the exclusive remedies for a breach of this Article V or Articles III or IV above but shall be in addition to all remedies available at law or in equity, including the recovery of damages from Executive and Executive's agents.

1.4 **Reasonableness; Enforcement**. Executive hereby represents to the Company that Executive has read and understands, and agrees to be bound by, the terms of this Article V. Executive acknowledges that the geographic scope and duration of the covenants contained in this Article V are the result of arm's-length bargaining and are fair and reasonable in light of (a) the nature and wide geographic scope of the operations of the Company's business, (b) Executive's level of control over and contact with the Company's business throughout the Restricted Area, (c) the fact that the Business is conducted by the Company throughout the Restricted Area, (d) the fact that Executive's duties are fulfilled throughout, materially relate to work performed by the Company throughout, the Restricted Area, (e) the compensation and Confidential Information that Executive has received and will receive in conjunction with Executive's employment with the Company and (f) the goodwill that Executive has built and will continue to help build during Executive's employment by the Company. It is the desire and intent of the Parties that the provisions of this Article V be enforced to the fullest extent permitted under any applicable laws, whether now or hereafter in effect. Executive and the Company hereby waive any provision of any applicable Legal Requirements that would render any provision of this Article V invalid or unenforceable.

1.5 **Reformation**. The Company and Executive agree that the foregoing restrictions are reasonable under the circumstances and that any breach of the covenants contained in this Article V would cause irreparable injury to the Company. Executive understands that the foregoing restrictions may limit Executive's ability to engage in Competing Businesses in the Restricted Area during the Prohibited Period, but acknowledges that Executive will receive sufficiently high remuneration and other benefits from the Company to justify such restriction. Further, Executive acknowledges that Executive's skills are such that Executive can be gainfully employed in non-competitive employment, and that Executive's agreement not to compete will not prevent Executive from earning a living. Nevertheless, if any of the aforesaid restrictions are found by a court of competent jurisdiction to be unreasonable, or overly broad as to geographic area or time, or otherwise unenforceable, the Parties intend for the restrictions herein set forth to be modified by the court making such determination so as to be reasonable and enforceable and, as so modified, to be fully enforced. By agreeing to this contractual modification prospectively at this time, the Company and Executive intend to make this provision enforceable under all applicable laws so that the entire non-competition agreement of Article V and this entire Agreement as prospectively modified shall remain in full force and effect and shall not be rendered void or illegal.

Article VI
DISPUTE RESOLUTION

1.1 **Dispute Resolution**.

(a) Subject to Section 6.1(b), any dispute, controversy or claim between Executive and the Company or any of its Affiliates arising out of or relating to this Agreement or Executive's employment with the Company or any of its Affiliates will be finally settled by arbitration in Houston, Texas before, and in accordance with the then-existing American Arbitration Association ("AAA") Employment Arbitration Rules. The arbitration award shall be final and binding on both Parties. Any arbitration conducted under this Article VI shall be heard by a single arbitrator (the "Arbitrator") selected in accordance with the then-applicable rules of the AAA. The Arbitrator shall expeditiously hear and decide all matters concerning the dispute. Except as expressly provided to the contrary in this Agreement, the Arbitrator shall have the power to (i) gather such materials, information, testimony and evidence as the Arbitrator deems relevant to the dispute before him or her (and each party will provide such materials, information, testimony and evidence requested by the Arbitrator), and (ii) grant injunctive relief and enforce specific performance. The decision of the Arbitrator shall be reasoned, rendered in writing, be final and binding upon the disputing Parties and the Parties agree that judgment upon the award may be entered by any court of competent jurisdiction; *provided*, *however*, that the Parties agree that the Arbitrator and any court enforcing the award of the Arbitrator shall not have the right or authority to award punitive or exemplary damages to any disputing Party. The Party whom the Arbitrator determines is the prevailing Party in such arbitration shall receive, in addition to any other award pursuant to such arbitration or associated judgment, reimbursement from the other Party of all reasonable legal fees and costs; *provided*, *however*, that if such arbitration occurs during the CIC Protection Period and Executive prevails on at least one material claim, the Company shall reimburse Executive for all reasonable legal fees and costs in connection with such dispute.

(b) Notwithstanding Section 6.1(a), either Party may make a timely application for, and obtain, judicial emergency or temporary injunctive relief; *provided*, *however*, that the remainder of any such dispute (beyond the application for emergency or temporary injunctive relief) shall be subject to arbitration under this Article VI.

(c) By entering into this Agreement and entering into the arbitration provisions of this Article VI, THE PARTIES EXPRESSLY ACKNOWLEDGE AND AGREE THAT THEY ARE KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVING THEIR RIGHTS TO A JURY TRIAL.

(d) Nothing in this Article VI shall prohibit a Party to this Agreement from (i) instituting litigation to enforce any arbitration award, or (ii) joining another party to this Agreement in a litigation initiated by a Person which is not a Party to this Agreement.

Article VII
MISCELLANEOUS

1.1 **Notices**. For purposes of this Agreement, notices and all other communications provided for herein shall be in writing and shall be deemed to have been duly given (a) when received if delivered personally or by courier, (b) on the date receipt is acknowledged if delivered by certified mail, postage prepaid, return receipt requested or (c) one day after transmission if sent by facsimile transmission with confirmation of transmission, as follows:

If to Executive, addressed to:

[Executive Address]

If to the Company, addressed to:

Black Stone Natural Resources Management Company
1001 Fannin Street, Suite 2020
Houston, Texas 77002
Attention: General Counsel

or to such other address as either Party may furnish to the other in writing in accordance herewith, except that notices or changes of address shall be effective only upon receipt.

1.2 **Applicable Law; Submission to Jurisdiction**.

(a) This Agreement is entered into under, and shall be governed for all purposes by, the Legal Requirements of the State of Texas, without regard to conflicts of laws principles thereof.

(b) With respect to any action to obtain emergency, temporary or preliminary injunctive relief as permitted by Articles III, IV or V above, the Parties hereto hereby consent to the exclusive jurisdiction, forum and venue of the state and federal courts residing in, or with jurisdiction over, Harris County, Texas. The Parties recognize that such forum and venue is convenient and directly and materially related to their employment relationship and this Agreement.

1.3 **No Waiver**. No failure by either Party hereto at any time to give notice of any breach by the other Party of, or to require compliance with, any condition or provision of this Agreement shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time.

1.4 **Severability**. If an arbitrator or a court of competent jurisdiction determines that any provision (or part thereof) of this Agreement is invalid or unenforceable, then the invalidity or unenforceability of that provision (or part thereof) shall not affect the validity or enforceability of any other provision of this Agreement, and all other provisions shall remain in full force and effect.

1.5 **Counterparts**. This Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original, but all of which together will constitute one and the same Agreement.

1.6 **Withholding of Taxes**. The Company may withhold from any payments made pursuant to this Agreement all federal, state, city and other taxes as may be required pursuant to any applicable laws.

1.7 **Title and Headings; Construction**. Titles and headings to Sections hereof are for the purpose of reference only and shall in no way limit, define or otherwise affect the provisions hereof. Unless the context requires otherwise, all references herein to an agreement, plan, instrument or other document shall be deemed to refer to such agreement, plan, instrument or other document as amended, supplemented, modified and restated from time to time to the extent permitted by the provisions thereof. The word "or" as used herein is not exclusive and is deemed to have the meaning "and/or." The words "herein", "hereof", "hereunder" and other compounds of the word "here" shall refer to the entire Agreement, including all Exhibits attached hereto, and not to any particular provision hereof. Wherever the context so requires, the masculine gender includes the feminine or neuter, and the singular number includes the plural and conversely. The use herein of the word "including" following any general statement, term or matter shall not be construed to limit such statement, term or matter to the specific items or matters set forth immediately following such word or to similar items or matters, whether or not non-limiting language (such as "without limitation", "but not limited to", or words of similar import) is used with reference thereto, but rather shall be deemed to refer to all other items or matters that could reasonably fall within the broadest possible scope of such general statement, term or matter. Neither this Agreement nor any uncertainty or ambiguity herein shall be construed or resolved against any party hereto, whether under any rule of construction or otherwise. On the contrary, this Agreement has been reviewed by each of the parties hereto and shall be construed and interpreted according to the ordinary meaning of the words used so as to fairly accomplish the purposes and intentions of the parties hereto.

1.8 **Assignment**. This Agreement and the rights hereunder are personal in nature and may not be assigned by Executive without the prior written consent of the Company. In addition, any payment owed to Executive hereunder after the date of Executive's death shall be paid to Executive's estate. Subject to the preceding provisions of this Section 7.8, this Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns.

1.9 **At-Will Employment**. Nothing in this Agreement shall affect the at-will nature of Executive's employment, as the Company or Executive may terminate the employment relationship at any time and for any reason or no reason at all.

1.10 **Entire Agreement**. Subject to the remainder of this Section 7.10, this Agreement constitutes the entire agreement of the Parties with regard to the subject matter hereof, and contains all the covenants, promises, representations, warranties and agreements between the Parties with respect to the subject matter hereof. Notwithstanding the foregoing, the Parties expressly acknowledge and agree that this Agreement does not supersede or replace, but instead complements and is in addition to, all non-competition, non-solicitation, confidentiality and other restrictive covenant provisions as well as all severance and termination-related provisions in all other equity compensation agreements between Executive and the Company, the Partnership, the General Partner or any of their respective Affiliates, whether granted pursuant to the LTIP or otherwise.

1.11 **Modification; Waiver; Termination**. Any modification, waiver or termination of this Agreement will be effective only if it is in writing and signed by both of the Parties.

1.12 **Third-Party Beneficiaries**. Each Affiliate of the Company shall be a third-party beneficiary of Executive's obligations under Articles III, IV and V above and shall be entitled to enforce such obligations as if a party hereto.

1.13 **Internal Revenue Code Section 409A**. This Agreement is not intended to provide for any deferral of compensation subject to Section 409A of the Internal Revenue Code of 1986, as amended and the Treasury regulations and other interpretive guidance issued thereunder (collectively, "Section 409A"). Any payments to be made under this Agreement upon a termination of Executive's employment shall only be made if such termination of employment constitutes a "separation from service" under Section 409A. Notwithstanding any provision in this Agreement to the contrary, if any payment or benefit provided for herein would be subject to additional taxes and interest under Section 409A if Executive's receipt of such payment or benefit is not delayed until the earlier of (a) the date of Executive's death or (b) the date that is six months after the date of termination of Executive's employment with the Company (such date, the "Section 409A Payment Date"), then such payment or benefit shall not be provided to Executive (or Executive's estate, if applicable) until the Section 409A Payment Date. Notwithstanding the foregoing, the Company makes no representations that the payments and benefits provided under this Agreement are exempt from, or compliant with, Section 409A and in no event shall the Company be liable for all or any portion of any taxes, penalties, interest or other expenses that may be incurred by Executive on account of non-compliance with Section 409A.

[Remainder of Page Intentionally Blank;
Signature Page Follows]

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement effective as of the Effective Date.

BLACK STONE NATURAL RESOURCES MANAGEMENT COMPANY

By: ______________
[BSNR Management Authorized Person]

EXECUTIVE

____
[Executive]

Exhibit 21.1

SUBSIDIARIES OF BLACK STONE MINERALS, L.P.

Entity	Jurisdiction of Organization
Black Stone Energy Company, L.L.C.	Texas
BSMC Louisiana LLC	Delaware
Black Stone Minerals Company, L.P.	Delaware
Black Stone Minerals GP, L.L.C.	Delaware
Black Stone Natural Resources, L.L.C.	Delaware
Black Stone Natural Resources Management Company	Texas
BSMC GP, L.L.C.	Delaware
NAMP Holdings, LLC	Delaware
NAMP GP, LLC	Oklahoma
NAMP 1, L.P.	Oklahoma
NAMP 2, L.P.	Oklahoma

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-262227) pertaining to the Long-Term Incentive Plan of Black Stone Minerals, L.P.,

(2) Registration Statement (Form S-8 No. 333-203909) pertaining to the Long-Term Incentive Plan of Black Stone Minerals, L.P.,

(3) Registration Statement (Form S-3 No. 333-234455) of Black Stone Minerals, L.P.;

of our reports dated February 20, 2024, with respect to the consolidated financial statements of Black Stone Minerals, L.P. and subsidiaries and the effectiveness of internal control over financial reporting of Black Stone Minerals, L.P. and subsidiaries included in this Annual Report (Form 10-K) of Black Stone Minerals, L.P. for the year ended December 31, 2023.

/s/ Ernst & Young LLP

Houston, Texas
February 20, 2024

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use of the name Netherland, Sewell & Associates, Inc., the references to our report of Black Stone Minerals, L.P.'s proved oil and natural gas reserves estimates and future net revenue as of December 31, 2023, and the inclusion of our corresponding report letter, dated January 10, 2024, in the 2023 Annual Report on Form 10-K (the "Annual Report") of Black Stone Minerals, L.P. We hereby also consent to the incorporation by reference of such report and the information contained therein in the Registration Statement on Form S-8 (File No. 333-262227), Form S-8 (No. 333-203909), and Form S-3 (No. 333-234455) of Black Stone Minerals, L.P.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

Houston, Texas
February 20, 2024

Exhibit 31.1

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

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

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

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

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

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

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

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

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

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

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

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

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

Date: February 20, 2024

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

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

I, Evan M. Kiefer, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 20, 2024

/s/ Evan M. Kiefer
Evan M. Kiefer
Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Exhibit 32.1

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

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

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

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

Date: February 20, 2024

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

Date: February 20, 2024

/s/ Evan M. Kiefer
Evan M. Kiefer
Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Black Stone Minerals, L.P.
Incentive-Based Compensation Recoupment Policy
(this "**Policy**")

Adopted October 18, 2023

Adopted by the Board of Directors (the "**Board**") of Black Stone Minerals GP, L.L.C. (the "**General Partner**") on behalf of Black Stone Minerals, L.P. (the "**Partnership**") on October 18, 2023. This Policy, as amended, will be administered by the Compensation Committee (the "**Administrator**"). This Policy is effective as of October 18, 2023, and supersedes and replaces that certain Black Stone Minerals, L.P. Incentive Compensation Recoupment Policy, originally effective as of April 26, 2017, in its entirety.

1. Recoupment. If the Partnership is required to prepare a Restatement, the Administrator shall, unless determined to be Impracticable, take reasonably prompt action to recoup all Recoverable Compensation from any Covered Person. This Policy is in addition to (and not in lieu of) any right of repayment, forfeiture or off-set against any Covered Person that may be available under applicable law or otherwise (whether implemented prior to or after adoption of this Policy). The Administrator may, in its sole discretion and in the exercise of its business judgment, determine whether and to what extent additional action is appropriate to address the circumstances surrounding any recovery of Recoverable Compensation tied to a Restatement and to impose such other discipline as it deems appropriate.

2. Method of Recoupment. Subject to applicable law, the Administrator may seek to recoup Recoverable Compensation by (i) requiring a Covered Person to repay such amount to the Partnership or General Partner; (ii) offsetting a Covered Person's other compensation; or (iii) such other means or combination of means as the Administrator, in its sole discretion, determines to be appropriate. To the extent that a Covered Person fails to repay all Recoverable Compensation to the Partnership or General Partner as determined pursuant to this Policy, the Partnership shall take all actions reasonable and appropriate to recover such amount, subject to applicable law.

3. Administration of Policy. The Administrator shall have full authority to administer, amend or terminate this Policy. The Administrator shall, subject to the provisions of this Policy, make such determinations and interpretations and take such actions in connection with this Policy as it deems necessary, appropriate or advisable. All determinations and interpretations made by the Administrator shall be final, binding and conclusive. Notwithstanding anything in this Section 3 to the contrary, no amendment or termination of this Policy shall be effective if such amendment or termination would (after taking into account any actions taken by the Partnership contemporaneously with such amendment or termination) cause the Partnership to violate any federal securities laws, rules of the U.S. Securities and Exchange Commission (the "**SEC**") or the rules of any national securities exchange or national securities association on which the Partnership's securities are then listed. The Administrator shall consult with the Partnership's audit committee, chief financial officer and chief accounting officer, as applicable, as needed in order to properly administer and interpret any provision of this Policy.

4. Acknowledgement by Executive Officers. The Administrator may provide notice to and seek written acknowledgement of this Policy from each Executive Officer; provided that the failure to provide such notice or obtain such acknowledgement shall not affect the applicability or enforceability of this Policy.

5. No Indemnification. Notwithstanding the terms of any of the Partnership's organizational documents, any corporate policy, or any other contract, neither the Partnership nor the General Partner shall be required to indemnify any Covered Person against the loss of any Recoverable Compensation.

6. Disclosures and Record Keeping. The Partnership shall make all disclosures and filings with respect to this Policy and maintain all documents and records that are required by the applicable rules and forms of the SEC (including, without limitation, Rule 10D-1 under the Securities Exchange Act of 1934 (the "**Exchange Act**")) and any applicable exchange listing standard.

7. Governing Law. The validity, construction, and effect of this Policy and any determinations relating to this Policy shall be construed in accordance with the laws of the State of Delaware without regard to its conflicts of laws principles.

8. Successors. This Policy shall be binding and enforceable against all Covered Persons and their beneficiaries, heirs, executors, administrators or other legal representatives.

9. Definitions. In addition to terms otherwise defined in this Policy, the following terms, when used in this Policy, shall have the following meanings:

"Applicable Period" means the three completed fiscal years preceding the earlier of: (i) the date that the Administrator, or the officer or officers of the Partnership authorized to take such action if Administrator action is not required, concludes, or reasonably should have concluded, that the Partnership is required to prepare a Restatement; or (ii) the date a court, regulator, or other legally authorized body directs the Partnership to prepare a Restatement. The Applicable Period shall also include any transition period (that results from a change in the Partnership's fiscal year) of less than nine months within or immediately following the three completed fiscal years. For purposes of this Policy, the Administrator shall be deemed to have reasonably concluded that a Restatement is required on the date that the Partnership's audit committee or the Partnership's chief accounting officer, as applicable, informs the Administrator in writing that such a Restatement will be required, unless the Partnership's audit committee informs the Administrator that an alternative date is more accurate for purposes of determining the Applicable Period.

"Covered Person" means any person who receives Recoverable Compensation.

"Executive Officer" includes the General Partner's principal executive officer, president, principal financial officer, principal accounting officer (or if there is no such accounting officer, the controller), any senior vice president or vice president of the General Partner in charge of a principal business unit or function (such as land, reservoir engineering, legal, or finance), any other officer who performs a policy-making function, or any other person (including any executive officer of the General Partner's controlled affiliates) who performs similar policy-making functions for the General Partner.

"Financial Reporting Measure" means a measure that is determined and presented in accordance with the accounting principles used in preparing the Partnership's financial statements (including "non-GAAP" financial measures, such as those appearing in earnings releases), and any measure that is derived wholly or in part from such measure. Stock price and total shareholder return ("**TSR**") are Financial Reporting Measures. Examples of additional Financial Reporting Measures include measures based on: revenues, net income, operating income, financial ratios, EBITDA, liquidity measures, return measures (such as return on assets), or profitability of one or more segments.

"Impracticable" means, after exercising a normal due process review of all the relevant facts and circumstances and taking all steps required by Exchange Act Rule 10D-1 and any applicable exchange listing standard, the Administrator determines that recovery of the Incentive-Based Compensation is impracticable because: (i) it has determined that the direct expense that the Partnership or General Partner would pay to a third party to assist in recovering the Incentive-Based Compensation would exceed the amount to be recovered; (ii) it has concluded that the recovery of the Incentive-Based Compensation would violate home country law adopted prior to November 28, 2022; or (iii) it has determined that the recovery of Incentive-Based Compensation would cause a tax-qualified retirement plan, under which benefits are broadly available to the Partnership's or General Partner's employees, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder.

"Incentive-Based Compensation" includes any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure; however it does not include: (i) base salaries; (ii) discretionary cash bonuses; (iii) awards (either cash or equity) that are based upon subjective, strategic or operational standards; and (iv) equity awards that vest solely on the passage of time.

"Received" – Incentive-Based Compensation is deemed "Received" in any Partnership fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of that period.

"Recoverable Compensation" means all Incentive-Based Compensation (calculated on a pre-tax basis) Received after October 2, 2023 by a person: (i) after beginning service as an Executive Officer; (ii) who served as an Executive Officer at any time during the performance period for that Incentive-Based Compensation; (iii) while the Partnership had a class of securities listed on a national securities exchange or national securities association; and (iv) during the Applicable Period, that exceeded the amount of Incentive-Based Compensation that otherwise would have been Received had the amount been determined based on the Financial Reporting Measures, as reflected in the Restatement. With respect to Incentive-Based Compensation based on unit price or TSR, when the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in a Restatement, the amount must be based on a reasonable estimate of the effect of the Restatement on the unit price or TSR upon which the Incentive-Based Compensation was received.

"Restatement" means an accounting restatement of any of the Partnership's financial statements due to the Partnership's material noncompliance with any financial reporting requirement under U.S. securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements (often referred to as a "Big R" restatement), or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (often referred to as a "little r" restatement). As of the effective date of this Policy (but subject to changes that may occur in accounting principles and rules following the effective date), a Restatement does not include situations in which financial statement changes did not result from material non-compliance with financial reporting requirements, such as, but not limited to retrospective: (i) application of a change in accounting principles; (ii) revision to reportable segment information due to a change in the structure of the Partnership's internal organization; (iii) reclassification due to a discontinued operation; (iv) application of a change in reporting entity, such as from a reorganization of entities under common control; (v) adjustment to provision amounts in connection with a prior business combination; and (vi) revision for unit splits, unit dividends, reverse unit splits or other changes in capital structure.

January 10, 2024

Mr. Garrett Gremillion
Black Stone Minerals, L.P.
1001 Fannin Street, Suite 2020
Houston, Texas 77002

Dear Mr. Gremillion:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2023, to the Black Stone Minerals, L.P. (Black Stone) interest in certain oil and gas properties located in the United States. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Black Stone. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Black Stone's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Black Stone interest in these properties, as of December 31, 2023, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	19,091.2	225,759.4	1,836,821.4	972,173.4
Proved Developed Non-Producing	—	2,301.7	3,863.6	3,012.8
Proved Undeveloped	—	44,234.8	69,804.6	47,737.3
Total Proved	19,091.2	272,296.0	1,910,489.6	1,022,923.5

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Black Stone's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Black Stone's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2023. For oil volumes, the average West Texas Intermediate spot price of $78.21 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.637 per MMBTU is adjusted for energy content, transportation fees, and market differentials. When applicable, gas prices have been adjusted to include the value for natural gas liquids. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $76.90 per barrel of oil and $2.629 per MCF of gas.

Operating costs used in this report are based on operating expense records of Black Stone, where available. For other properties, we have estimated operating costs based on our knowledge of similar operations in the area. Operating costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses of Black Stone are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Black Stone and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Black Stone's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Black Stone interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Black Stone receiving its net revenue interest share of estimated future gross production. Additionally, we have been informed by Black Stone that they are not aware of any firm transportation contracts to which Black Stone is a party that contain volume commitments which might represent a liability to the company; no adjustments have been made to our estimates of future revenue to account for such contracts.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Black Stone, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, analogy, and material balance, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Black Stone, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Connor B. Riseden, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 4 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E.
Chief Executive Officer

/s/ Connor B. Riseden
By:
Connor B. Riseden, P.E. 100566
Vice President

Date Signed: January 10, 2024

LPV:LRG

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is 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.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is 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 gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): 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

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.