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, 2022

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 x 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 x

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 x 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 x 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	x	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 x

The aggregate market value of the common units held by non-affiliates was $2,278,235,601 on June 30, 2022, the last business day of the registrant's most recently completed second fiscal quarter, based on a closing price of $13.69 per unit as reported by the New York Stock Exchange on such date. As of February 17, 2023, 209,683,640 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 list includes a description of the meanings of some of the oil and gas industry terms used in this Annual Report on Form 10-K ("Annual Report").

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

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

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

Bbl/d. Bbl per day.

Bcf. One billion cubic feet of natural gas.

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

Boe/d. Boe per day.

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

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

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

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

Delaware Act. Delaware Revised Uniform Limited Partnership Act.

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

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

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

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

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

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

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

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

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

GLOSSARY OF TERMS

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

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

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

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

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

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

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

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

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

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

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

Log. A measurement that provides 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.

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.

GLOSSARY OF TERMS

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.

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 commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

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 to unitholders;
- 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;
    - 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;
- 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;
    - Unitholders may have liability to repay distributions pursuant to Delaware law and common units may be subject to redemption; and
    - Tax-related risks;
- 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, and 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.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

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

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 over 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.

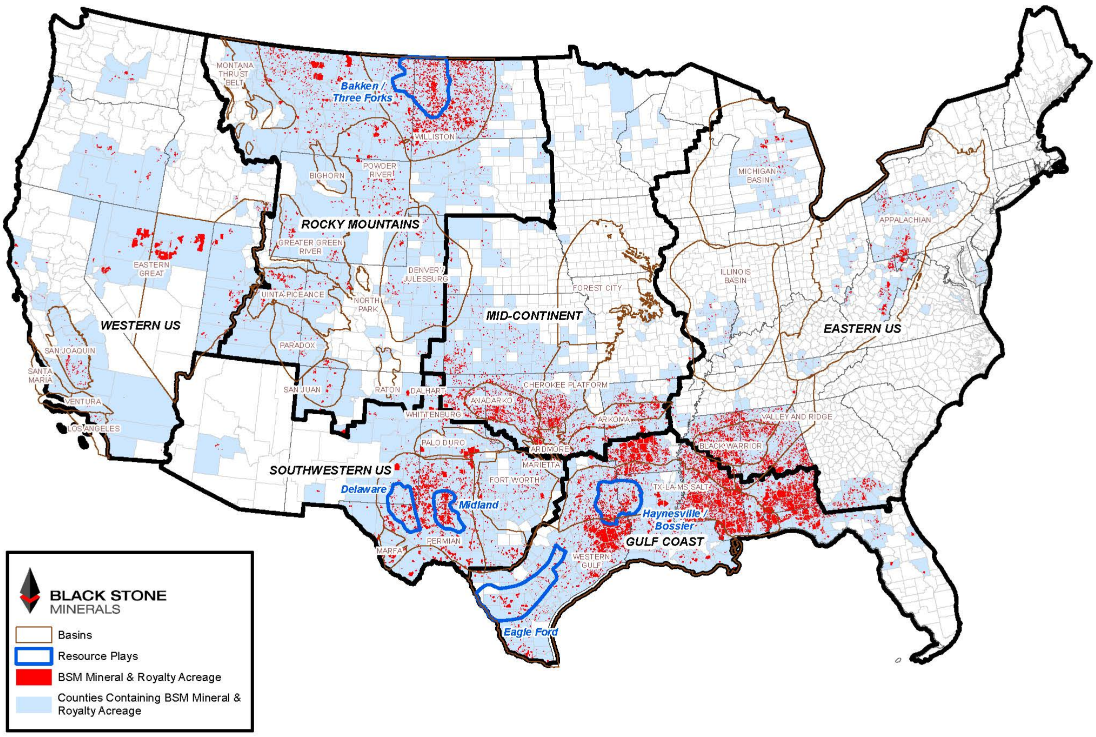
We are a publicly traded Delaware limited partnership formed on September 16, 2014. Our common units trade on the New York Stock Exchange under the symbol "BSM."

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, 2022, our total estimated proved oil and natural gas reserves were 64,115 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, 2022, approximately 91% were proved developed reserves and approximately 9% were proved undeveloped reserves. At December 31, 2022, 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, 2022, approximately 26% of our mineral and royalty interests are leased, calculated on a cumulative gross acreage basis for all three types of mineral and royalty interests.

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

Non-Operated Working Interests

We own non-operated working interests related to our mineral interests in various plays across our asset base. The majority of our working interest exposure is in the Haynesville/Bossier play in San Augustine County, Texas and Angelina County, Texas where we own non-operated working interests. We have farmout arrangements in place for our entire working interest position in that area. In 2022, we also entered into agreements with multiple operators to drill wells in the Austin Chalk in East Texas, where we have significant acreage positions and in some instances are participating alongside our operators as a working interest partner. 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 generally only 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.

Beginning in 2017, we significantly reduced the number of wells in which we participate with a working interest. We generally farm out 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 8% of our total production volumes during the year ended December 31, 2022. As of December 31, 2022, we owned non-operated working interests in 3,186 gross (177 net) wells.

Our 2023 capital expenditure budget associated with our non-operated working interests is expected to be approximately $6.9 million. The majority of this capital is anticipated to be spent on a well in the Austin Chalk play and the remaining will be spent for workovers and recompletions on existing wells in which we own a working interest in the Shelby Trough play.

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.

In 2017, we entered into farmout arrangements with Canaan Resource Partners ("Canaan") and Pivotal Petroleum Partners ("Pivotal") in the Shelby Trough area of East Texas where we own a concentrated, relatively high-interest royalty position. This area was under active development by XTO Energy Inc. ("XTO") in San Augustine County, Texas and BPX Energy in Angelina County, Texas through 2019. These farmout agreements were superseded and replaced by the new farmout agreements discussed below.

San Augustine Farmout

In March 2021, we reached an agreement with XTO to partition jointly owned working interests in the San Augustine County development area. Under the partition agreement, we exchanged working interests with XTO 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, we entered into an agreement with Aethon Energy ("Aethon") to develop certain of our 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 our 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, ten wells to be drilled in the second and third program years, and, beginning with the fourth program year, a minimum of twelve wells per year thereafter. Our development agreement with Aethon and related drilling commitments covering our San Augustine County acreage is independent of the development agreement and associated commitments covering Angelina County discussed below.

In May 2021, we entered into a new farmout agreement (the "Canaan Farmout") with Canaan and in December 2021, we entered into a farmout agreement (the "Azul Farmout") with Azul-SA, LLC ("Azul"). In April 2022, we amended the Canaan Farmout and entered into a farmout agreement (the "JWM Farmout") with JWM Oil & Gas LLC ("JWM"). These agreements cover all our working interests under active development by Aethon in San Augustine County, Texas and continue for a ten year period, unless earlier terminated in accordance with the terms of the agreements. Canaan, Azul, and JWM will each earn a percentage of our 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 our working interest for the duration of each farmout agreement. We 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, 2022, ten 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, we entered into an agreement with Aethon to develop certain portions of the area forfeited by BPX Energy in Angelina County, Texas. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to our mineral and leasehold acreage in the contract area. The agreement calls for a minimum of four wells to be drilled in the initial program year, which began in the third quarter of 2020, ten wells to be drilled in the second program year, and, beginning with the third program year, fifteen wells per year thereafter.

In November 2020, we entered into a new farmout agreement (the "Pivotal Farmout") with Pivotal. The Pivotal Farmout covers our 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 our 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 our working interests for the duration of the Pivotal Farmout. Once Pivotal achieves a specified payout for a designated well group, we will obtain a majority of the original working interest in such well group. As of December 31, 2022, a total of eighteen wells have been spud in the contract area subject to the Pivotal Farmout.

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.

The following tables present information about our mineral and royalty interests and working interests by BSM Land Region:

	Acreage as of December 31, 2022[1]							
	Mineral and Royalty Interests						Working Interests[2]	
BSM Land Region	Mineral Interests		NPRIs		ORRIs			
	Gross Acres	Net %[3]	Gross Acres	Net %[4]	Gross Acres	Net %[4]	Gross Acres	Net Acres
Gulf Coast	7,911,044	52.0 %	553,131	4.7 %	188,434	2.9 %	327,201	80,696
Southwestern U.S.	2,768,808	25.4 %	993,409	3.9 %	196,687	1.7 %	17,961	11,961
Rocky Mountains	2,123,593	15.4 %	243,159	3.4 %	857,944	2.5 %	84,821	14,988
Eastern U.S.	1,656,801	47.4 %	1,727	4.0 %	74,247	1.3 %	13,468	1,375
Mid-Continent	1,309,068	34.6 %	38,812	4.3 %	280,813	3.7 %	53,391	31,083
Western U.S.	1,025,566	89.2 %	331	1.8 %	28,657	3.2 %	—	—
Total	16,794,880	43.5 %	1,830,569	4.1 %	1,626,782	2.6 %	496,842	140,103

[1] 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, 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.

[2] This excludes acreage for which we have incomplete seller records.

[3] 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.

[4] 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.

			Mineral and Royalty Interests			Working Interests		
	Gross Well Count as of December 31, 2022[1]		Average Daily Production (Boe/d) for the Year Ended December 31,			Average Daily Production (Boe/d) for the Year Ended December 31,		
BSM Land Region	MRI Wells[2]	WI Wells	2022	2021	2020	2022	2021	2020
Gulf Coast	14,047	1,332	21,019	19,539	18,878	2,108	3,820	6,491
Southwestern U.S.	26,813	632	5,703	5,442	6,388	69	134	143
Rocky Mountains	15,197	819	4,545	5,138	4,983	534	585	680
Eastern U.S.	1,573	7	835	754	907	3	16	17
Mid-Continent	9,077	394	1,972	1,796	1,986	84	555	837
Western U.S.	598	2	261	267	273	—	—	—
Total	67,305	3,186	34,335	32,936	33,415	2,798	5,110	8,168

[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, 2022.

- ***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.

The following tables present information about our mineral and royalty interests and non-operated working interests by material resource play.

	Acreage as of December 31, 2022[1]							
	Mineral and Royalty Interests						Working Interests[2]	
Resource Play	Mineral Interests		NPRIs		ORRIs			
	Gross Acres	Net %[3]	Gross Acres	Net %[4]	Gross Acres	Net %[4]	Gross Acres	Net Acres
Bakken/ Three Forks	397,340	17.0 %	38,544	1.4 %	12,809	1.3 %	48,484	6,544
Haynesville/Bossier	402,865	61.2 %	28,516	3.1 %	26,660	5.8 %	157,036	32,844
Permian-Midland	221,470	4.9 %	128,486	2.3 %	102,536	0.4 %	160	4
Permian-Delaware	133,797	9.4 %	39,743	2.6 %	5,163	3.1 %	2,320	910
Eagle Ford	67,414	14.4 %	106,729	1.3 %	48,220	2.2 %	1,147	87

[1] 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, 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.

[2] This excludes acreage for which we have incomplete seller records.

[3] 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.

[4] 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.

			Mineral and Royalty Interests			Working Interests		
	Gross Well Count as of December 31, 2022[1]		Average Daily Production (Boe/d) for the Year Ended December 31,			Average Daily Production (Boe/d) for the Year Ended December 31,		
Resource Play	MRI Wells[2]	WI Wells	2022	2021	2020	2022	2021	2020
Bakken/ Three Forks	4,152	523	3,458	3,848	3,694	377	408	485
Haynesville/Bossier	1,236	92	16,867	15,935	14,525	1,504	3,179	5,756
Permian-Midland	2,854	4	2,623	2,457	2,640	—	—	—
Permian-Delaware	810	11	1,902	1,725	2,136	24	39	39
Eagle Ford	988	27	1,122	838	1,137	8	15	9

[1] We own both mineral and royalty interests and working interests in 618 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, 2022, 2021, and 2020 shown herein have been independently evaluated by 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 Richard B. Talley, Jr. Mr. Talley, a Licensed Professional Engineer in the State of Texas (License No. 102425), has been practicing consulting petroleum engineering at NSAI since 2004 and has over five years of prior industry experience. He graduated from the University of Oklahoma in 1998 with a Bachelor of Science Degree in Mechanical Engineering and from Tulane University in 2001 with a Master of Business Administration Degree. As technical principal, Mr. Talley 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, 2022 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 2022, 2021 and 2020. Mr. Gremillion is a petroleum engineer with approximately 13 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, 2022, 2021, and 2020 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 employed technologies including, but not limited to, well logs, core analysis, geologic maps, and available down hole pressure and production data, seismic data, and well test 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. In addition to assessing reservoir continuity, geologic data from well logs, core analyses, and seismic data were used to estimate original oil and natural gas in place.

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 $94.14, $66.55, and $39.54 per barrel as of December 31, 2022, 2021, and 2020, 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 $6.36, $3.60, and $1.99 per MMBTU as of December 31, 2022, 2021, and 2020, 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 $92.01 per barrel for oil and $6.50 per Mcf for natural gas as of December 31, 2022, $63.17 per barrel for oil and $3.37 per Mcf for natural gas as of December 31, 2021, and $36.43 per barrel for oil and $1.60 per Mcf for natural gas as of December 31, 2020.

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,		
	2022	2021	2020
		(Unaudited)	
Estimated proved developed:			
Oil (MBbls)	19,184	19,111	15,952
Natural gas (MMcf)	236,529	224,222	230,411
Total (MBoe)	58,606	56,481	54,354
Estimated proved undeveloped:			
Oil (MBbls)	—	60	—
Natural gas (MMcf)	33,057	19,695	9,800
Total (MBoe)	5,509	3,343	1,633
Estimated proved reserves:			
Oil (MBbls)	19,184	19,171	15,952
Natural gas (MMcf)	269,586	243,917	240,211
Total (MBoe)	64,115	59,824	55,987
Percent proved developed	91.4 %	94.4 %	97.1 %

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.”

Additional information regarding our estimated proved reserves can be found in the notes to our consolidated financial statements included elsewhere in this Annual Report and the estimated proved reserve report as of December 31, 2022, which is included as an exhibit to this Annual Report.

Estimated Proved Undeveloped Reserves

As of December 31, 2022, our PUDs comprised 33,057 MMcf of natural gas, or 5,509 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, 2022 (in MBoe):

	Estimated Proved Undeveloped Reserves
	(Unaudited)
As of December 31, 2021	3,343
Acquisitions of reserves	—
Divestiture of reserves	—
Extensions and discoveries	5,509
Revisions of previous estimates	—
Transfers to estimated proved developed	(3,343)
As of December 31, 2022	5,509

New PUD reserves totaling 5,509 MBoe were added during the year ended December 31, 2022, resulting from development activities in the Haynesville/Bossier play. In 2022 we did not acquire or divest any PUD reserves.

During the year ended December 31, 2022, we had no upward revisions to PUD reserves and converted 3,343 MBoe of PUD reserves to PDP reserves.

During the year ended December 31, 2022, no costs were incurred relating to the development of locations that were classified as PUDs as of December 31, 2021. The PUDs that were developed during 2022 were primarily Haynesville/Bossier PUDs in which our working interest was farmed out. Additionally, during the year ended December 31, 2022, we incurred $0.7 million drilling, completing, and recompleting other wells that were not classified as PUDs as of December 31, 2021. There are no estimated future development costs projected for the development of PUD reserves associated with our working interests as of December 31, 2022. All our PUD drilling locations as of December 31, 2022 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, 2022, our PUD reserves consists of 14 wells in various stages of drilling or completions. As of December 31, 2022, approximately 9% 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, 2022, 26% of our production and 44% of our oil and natural gas revenues were related to oil and condensate production and sales, respectively. During the same period, natural gas and NGL sales were 74% of our production and 56% 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,		
	2022	2021	2020
Production:			
Oil and condensate (MBbls)	3,591	3,646	3,895
Natural gas (MMcf)[1]	59,778	61,445	67,945
Total (MBoe)	13,554	13,887	15,219
Average daily production (MBoe/d)	37.1	38.0	41.6
Realized Prices without Derivatives:			
Oil and condensate (per Bbl)	$ 93.65	$ 64.67	$ 38.16
Natural gas and natural gas liquids sales (per Mcf)[1]	$ 7.28	$ 4.16	$ 2.04
Unit Cost per Boe:			
Production costs and ad valorem taxes	$ 4.89	$ 3.59	$ 2.86

[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, 2022[1]		
	Mineral and Royalty Interests	Working Interests	
Well Type	Gross	Gross	Net
Oil	46,989	2,221	44
Natural Gas	20,316	965	133
Total	67,305	3,186	177

[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, 2022:

BSM Land Region	Developed Acreage[1]	Undeveloped Acreage[1]	Total Acreage[1]
Gulf Coast	440,771	8,211,838	8,652,609
Southwestern U.S.	629,218	3,329,686	3,958,904
Rocky Mountains	885,280	2,339,416	3,224,696
Eastern U.S.	82,218	1,650,557	1,732,775
Mid-Continent	523,543	1,105,150	1,628,693
Western U.S.	28,660	1,025,894	1,054,554
Total	2,589,690	17,662,541	20,252,231

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

Working Interests

The following table sets forth information relating to our acreage for our non-operated working interests as of December 31, 2022:

	Developed Acreage[1]		Undeveloped Acreage[1]		Total Acreage[1]	
BSM Land Region	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	299,276	69,526	27,925	11,170	327,201	80,696
Southwestern U.S.	17,961	11,961	—	—	17,961	11,961
Rocky Mountains	84,821	14,988	—	—	84,821	14,988
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	468,917	128,933	27,925	11,170	496,842	140,103

[1] 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, 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.

The following table lists the net undeveloped acres, the net acres expiring in the years ending December 31, 2023, 2024, and 2025, and, where applicable, the net acres expiring that are subject to extension options:

	2023 Expirations		2024 Expirations		2025 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.**
11,170	4,222	4,019	1,525	1,403	1	—

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,		
	2022	**2021**	**2020**
Gross development wells:			
Productive	1.0	2.0	—
Dry	—	—	—
Total	1.0	2.0	—
Net development wells:			
Productive	0.1	0.2	—
Dry	—	—	—
Total	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, 2022, 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 is 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. Recent 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. The Biden administration issued an executive order calling for the suspension, revision, or rescission, of a September 2020 rule rescinding certain methane standards and removing transmission and storage segments from the source category for certain regulations, and the reinstatement or issuance of methane emissions standards for new, modified, and existing oil and gas facilities. The

EPA has proposed regulations implementing the executive order and additional restrictions on methane and volatile organic compound emissions. 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. While no firm commitment or timeline to phase out or phase down all fossil fuels was made at the most recent meeting of the UN Framework Convention on Climate Change, there can be no guarantees that countries will not seek to implement such a phase out in the future.

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 proposals in 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. 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. In September 2022, the Federal Reserve announced that six of the U.S.' largest banks will participate in a pilot climate scenario analysis exercise, launched in early 2023, to enhance the ability of firms and supervisors to measure and manage climate-related financial risk. 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. Recent 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. 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:

	Year Ended December 31,		
	2022	2021	2020
XTO Energy Inc.	12%	19%	20%

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, 2022, Black Stone Management had 98 full-time employees and 10 contractors. Our largest departments are Accounting and Land Administration, which account for 32 and 26 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 may look within our organization for talent to fill those needs, ask for referrals from our team (who understand the diverse skill sets, high energy and forward-thinking attitude that contributes to delivering exceptional results), or work 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 24 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.

COVID. In March 2020, in response to the COVID pandemic, we implemented remote work arrangements for the majority of our employees. The added flexibility to work remotely, coming to the office when needed or for specific in-person meetings, as well as establishing core business hours for added flexibility, has been positively received by our workforce and provided a greater work-life balance during trying times. 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 during this time.

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, including as a result of global pandemics similar to COVID-19;
- 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 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, 2022		During the Five Years Prior to 2022		As of December 31,		
	High	Low	High[2]	Low[3]	2022	2021	2020
WTI spot crude oil ($/Bbl)[1]	$ 123.64	$ 71.05	$ 123.64	$ 8.91	$ 80.16	$ 75.33	$ 48.35
Henry Hub spot natural gas ($/MMBtu)[1]	9.85	3.46	23.86	1.33	3.52	3.82	2.36

[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 44% of our 2022 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, 2022, WTI market prices at Cushing, Oklahoma have ranged from a high of $123.64 per Bbl in 2022 to a low of $8.91 per Bbl in 2020. On December 31, 2022, the WTI spot market price of oil was $80.16. 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 recent 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 in addition to impairments taken during 2015, 2016, and 2020, 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 56% of our 2022 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, 2022, 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 31, 2022, the Henry Hub spot market price of natural gas was $3.52 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, rising levels of U.S. natural gas exports, and recent fluctuations in demand as a result of the COVID-19 pandemic. If prices for natural gas are depressed for an extended period of time or there are future declines, we may be required to further write down the value of our oil and natural gas properties in addition to impairments taken during 2015, 2016, and 2020, 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.

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, 2022, 2021, and 2020 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, 2022, 2021, and 2020 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, 2022, 2021, and 2020, 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, 2022, 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 2022, we generated 13% of our royalty revenues and 35% 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.

If any of these risks are realized and production is not replaced by another operator in this area or another area, 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, 2022, we had outstanding borrowings of $10.0 million 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 2022 was $550.0 million with outstanding commitments of $375.0 million and the next semi-annual redetermination is scheduled for April 2023. 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, it is possible that we 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 early 2023, but 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 or deficient.

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% per annum, subject to certain adjustments, 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, 2022, we had 209,406,927 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, 2022 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 Internal Revenue Service ("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. 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 audit adjustments to our income tax returns for tax years beginning after December 31, 2017, 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.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, 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 under these rules, 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. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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. 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 on or after January 1, 2023, 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 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

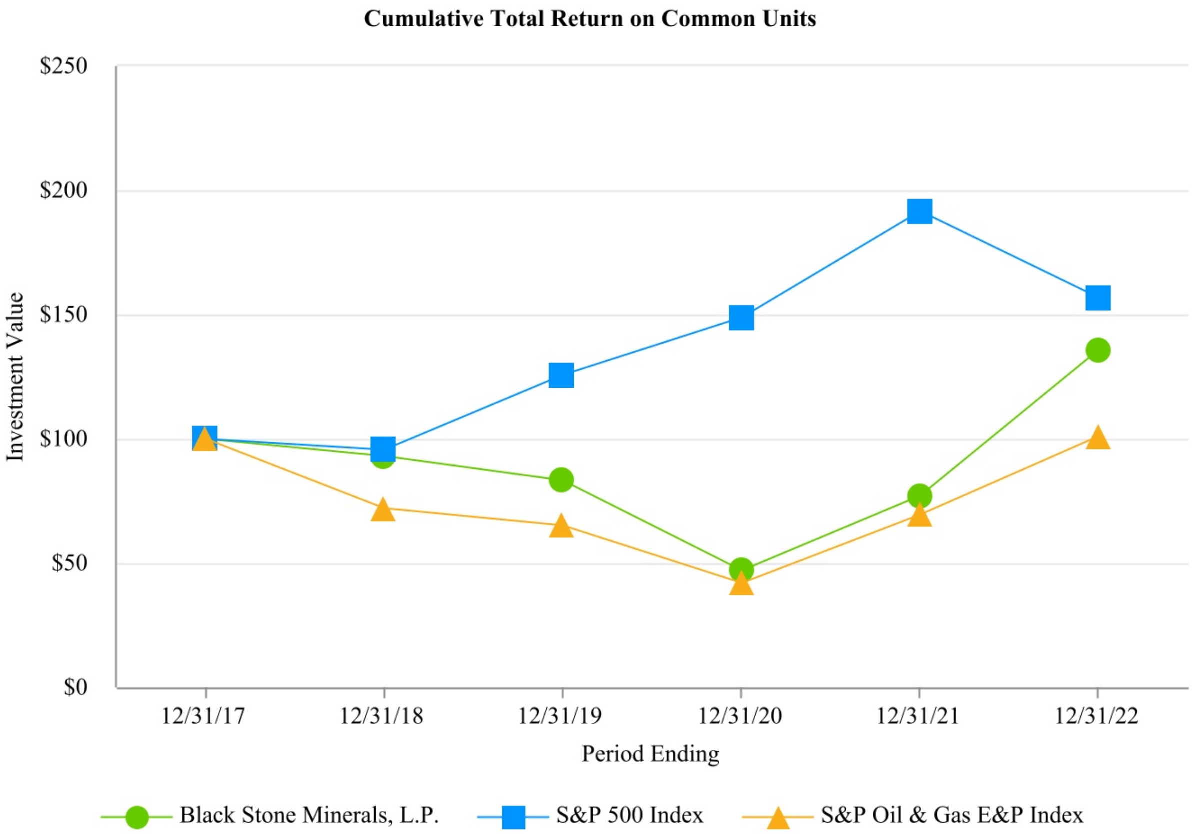
Not applicable.

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 17, 2023, there were 209,683,640 common units outstanding held by 389 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 17, 2023, 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 30, 2017. Cumulative return is computed assuming reinvestment of distributions.



Comparison of Cumulative Total Return
Assumes Initial Investment of $100

	As of December 31,					
	2017	2018	2019	2020	2021	2022
Black Stone Minerals, L.P.	$ 100.00	$ 92.77	$ 83.15	$ 46.88	$ 77.15	$ 135.78
S&P 500 Index	100.00	95.62	125.72	148.85	191.58	156.88
S&P Oil & Gas E&P Index	100.00	71.90	65.11	41.73	69.51	100.82

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% per annum, subject to certain adjustments; 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 3.50:1.00 or less and a current ratio of 1.00:1.00 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 receive cumulative quarterly distributions in an amount equal to 7.0% of the face amount of the preferred units per annum (the “Distribution Rate”), provided that the Distribution Rate will be adjusted as follows: commencing on November 28, 2023 and readjusting every two years thereafter (each, a “Readjustment Date”), the rate will equal 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 for a 90-day period beginning on November 28, 2023 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 2022 and 2021. For the discussion of changes from 2020 to 2021 and other financial information related to 2020, refer to "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our 2021 Annual Report on Form 10-K, which was filed with the SEC on February 22, 2022.

Overview

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

As of December 31, 2022, our mineral and royalty interests were located in 41 states in the continental United States including all of the major onshore producing basins. These non-cost-bearing interests include ownership in over 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

TLW Divestiture

In the third quarter of 2021, we closed on the divestiture of our 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.

Acquisitions

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

Shelby Trough Update

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

Austin Chalk Update

We own a large mineral position in the Brookeland Austin Chalk play in east Texas. To date, eighteen new generation, multi-stage completion wells have turned to sales across the Polk, Jasper, Newton area. Production results have proven that new completion technology can improve well performance in the play. We expect additional drilling by multiple operators over this area in the future.

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 continued to recover in 2022, due to several factors, including higher demand for oil, natural gas, and natural gas liquids ("NGLs") from the lows of the pandemic, ongoing crude oil production limits from members of the Organization of the Petroleum Exporting Countries and its broader partners, and supply constraints due to Russia's military invasion into Ukraine and the subsequent sanctions imposed on Russia. The invasion occurred in March 2022 when oil inventories were already low, and the possibility of sanctions or physical disruptions to Russia's oil production led to higher prices. Crude oil prices have fallen since then mainly because of slowing growth in global economic activity and oil consumption but remain above pre-pandemic levels. Natural gas prices remained high for much of 2022 as a result of increased demand for LNG exports and lower production compared with the end of 2021. However, prices decreased in the fourth quarter as a result of warmer-than-normal temperatures across much of the U.S. and a decrease in export capacity resulting from the closure of the Freeport LNG Gulf Coast export facility in June 2022. The current price environment remains uncertain as responses to elevated inflation, and the conflict in Ukraine continue to evolve. Given the dynamic nature of these events, we cannot reasonably estimate the period of time that 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:

	2022			
Benchmark Prices	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot crude oil ($/Bbl)[1]	$ 80.16	$ 79.91	$ 107.76	$ 100.53
Henry Hub spot natural gas ($/MMBtu)[1]	$ 3.52	$ 6.40	$ 6.54	$ 5.46

[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:

	2022			
U.S. Rotary Rig Count[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	621	604	594	531
Natural gas	156	159	157	137
Other	2	2	2	2
Total	779	765	753	670

[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 2023, at 1.8 Tcf, or 16% higher than the five-year average. The EIA expects inventories will rise to 3.8 Tcf at the end of October 2023, which would be 5% higher than the five-year average.

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

	2022			
Region[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
	(Bcf)			
East	691	756	461	268
Midwest	839	916	535	317
Mountain	157	184	134	89
Pacific	165	247	235	161
South Central	1,040	1,003	886	581
Total	2,892	3,106	2,251	1,416

[1] Source: EIA

Natural Gas Exports

On June 9, 2022, Freeport LNG shut down its Gulf Coast LNG export facility, which represents approximately 20% of the total U.S. export capacity, due to an explosion at the facility. As of February 2023, the plant has received small amounts of natural gas from pipelines and has resumed limited operations. The EIA believes increases in U.S. natural gas production, relatively flat LNG exports, and declining domestic consumption in the electric power and industrial sectors will limit upward pressure on prices in 2023. The EIA forecasts average exports of 11.8 Bcf per day for 2023.

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. The EIA expects increases in U.S. natural gas production, relatively flat LNG exports, and declining domestic consumption in the electric power and industrial sectors will limit upward pressure on prices in 2023.

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, 2022 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, 2022, we had hedged 81% of our available oil and condensate hedge volumes and 68% of our available natural gas hedge volumes for 2023.

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,	
	2022	2021
	(in thousands)	
Net income (loss)	$ 476,480	$ 181,987
Adjustments to reconcile to Adjusted EBITDA:		
Depreciation, depletion, and amortization	47,804	61,019
Interest expense	6,286	5,638
Income tax expense (benefit)	58	(135)
Accretion of asset retirement obligations	861	1,073
Equity-based compensation	17,388	12,218
Unrealized (gain) loss on commodity derivative instruments	(82,486)	33,528
(Gain) loss on sale of assets, net	(17)	(2,850)
Adjusted EBITDA	466,374	292,478
Adjustments to reconcile to Distributable cash flow:		
Change in deferred revenue	(30)	(18)
Cash interest expense	(4,282)	(4,059)
Preferred unit distributions	(21,000)	(21,000)
Distributable cash flow	$ 441,062	$ 267,401

Results of Operations

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

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

	Year Ended December 31,			
	2022	2021	Variance	
	(dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	3,591	3,646	(55)	(1.5)%
Natural gas (MMcf)[1]	59,778	61,445	(1,667)	(2.7)%
Equivalents (MBoe)	13,554	13,887	(333)	(2.4)%
Equivalents/day (MBoe)	37.1	38.0	(0.9)	(2.4)%
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 93.65	$ 64.67	$ 28.98	44.8 %
Natural gas ($/Mcf)[1]	7.28	4.16	3.12	75.0 %
Equivalents ($/Boe)	$ 56.90	$ 35.39	$ 21.51	60.8 %
Revenue:				
Oil and condensate sales	$ 336,287	$ 235,771	$ 100,516	42.6 %
Natural gas and natural gas liquids sales[1]	434,945	255,671	179,274	70.1 %
Lease bonus and other income	13,052	14,292	(1,240)	(8.7)%
Revenue from contracts with customers	784,284	505,734	278,550	55.1 %
Gain (loss) on commodity derivative instruments	(120,680)	(146,474)	25,794	(17.6)%
Total revenue	$ 663,604	$ 359,260	$ 304,344	84.7 %
Operating expenses:				
Lease operating expense	$ 12,380	$ 13,056	$ (676)	(5.2)%
Production costs and ad valorem taxes	66,233	49,809	16,424	33.0 %
Exploration expense	193	1,082	(889)	(82.2)%
Depreciation, depletion, and amortization	47,804	61,019	(13,215)	(21.7)%
General and administrative	53,652	48,746	4,906	10.1 %
Other expense:				
Interest expense	6,286	5,638	648	11.5 %

[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, 2022 increased compared to the year ended December 31, 2021. The increase in total revenue from the corresponding period is primarily due to higher realized commodity prices partially offset by lower production volumes. A decrease in the loss on commodity derivative instruments in 2022 further contributed to the overall increase in revenue.

Oil and condensate sales. Oil and condensate sales for the year ended December 31, 2022 were higher than the corresponding period in 2021 due to higher realized commodity prices partially offset by lower production volumes. The decrease in oil and condensate production was primarily due to reduced production volumes from the Bakken/Three Forks play trend. The decrease in Bakken/Three Forks production was driven by normal production declines with less new development activity. Our mineral and royalty interest oil and condensate volumes accounted for 93% of total oil and condensate volumes for each of the years ended December 31, 2022 and 2021.

Natural gas and natural gas liquids sales. Natural gas and NGL sales increased for the year ended December 31, 2022 as compared to the year ended December 31, 2021 due to higher realized commodity prices offset by lower production volumes. The decrease in natural gas and NGL production was driven by decreases in working interest production volumes, primarily within the Shelby Trough play. Mineral and royalty interest production accounted for 92% and 84% of our natural gas volumes for the years ended December 31, 2022 and 2021, 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 2022, we recognized $203.2 million of realized losses and $82.5 million of unrealized gains from our commodity derivatives, compared to $112.9 million of realized losses and $33.5 million of unrealized losses in 2021. The unrealized gains on our commodity contracts in 2022 and unrealized losses in 2021 were both primarily driven by changes in the forward commodity price curves for 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 lower for the year ended December 31, 2022, as compared to the same period in 2021. Leasing activity in the Wolfcamp and Haynesville/Bossier plays made up the majority of lease bonus and other income in 2022. Leasing activity in the Austin Chalk and Wolfcamp plays, as well as proceeds from surface use waivers on our mineral acreage supporting solar development in Mississippi, Texas, and California made up the majority of lease bonus and other income in 2021.

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 2022 as compared to 2021, primarily due to a decrease 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, 2022, production and ad valorem taxes increased as compared to the year ended December 31, 2021, as a result of higher commodity prices and higher ad valorem tax estimates.

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 2022 was minimal. Exploration expense for 2021 primarily related to a dry hole drilled in the first quarter of 2021.

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, 2022 as compared to 2021, primarily due to lower production volumes and a reduction in cost basis. The reduction in cost basis is primarily due to continued depreciation, depletion, and amortization.

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, 2022, general and administrative expenses increased compared to 2021, primarily due to a $1.9 million increase in cash compensation and a $4.8 million increase in equity-based compensation. The increase in cash compensation was driven by projected outperformance relative to performance targets under our short-term cash incentive plan. The increase in equity-based compensation was due to higher costs recognized for performance-based incentive awards resulting from upward movements in our common unit price during 2022 compared to 2021. The overall increase was partially offset by a $2.1 million recovery in allowance against an outstanding long-term receivable.

Other Expense

Interest expense. For the year ended December 31, 2022, interest expense increased compared to 2021, primarily due to higher interest rates under our Credit Facility.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations, borrowings under our Credit Facility, and proceeds from the issuance of equity and debt. Our primary uses of cash are for distributions to our unitholders, reducing outstanding borrowings under our Credit Facility, for investing in our business, specifically the acquisition of mineral and royalty interests and our selective participation on a non-operated working interest basis in the development of our oil and natural gas properties. We have the option to redeem Series B cumulative convertible preferred units beginning on November 28, 2023 (see Note 12).

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, proceeds from any future issuances of equity and debt, and proceeds from asset sales. Over the long-term, we intend to finance our working interest capital needs with our executed farmout agreements and internally generated cash flows, although at times we may fund a portion of these expenditures through other financing sources such as borrowings under our Credit Facility.

Cash Flows

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

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

	Year Ended December 31,		
	2022	2021	Change
	(in thousands)		
Cash flows provided by operating activities	$ 424,983	$ 256,880	$ 168,103
Cash flows provided by (used in) investing activities	(1,215)	(14,317)	13,102
Cash flows provided by (used in) financing activities	(428,337)	(235,483)	(192,854)

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 2022 increased as compared to 2021. The increase was primarily due an increase in oil and condensate sales revenue and natural gas and NGL sales revenue due to higher realized commodity prices in 2022 compared to the same period of 2021. The overall increase was partially offset by an increase in net cash paid on settlements of commodity derivative instruments.

Investing Activities. Net cash used in investing activities for 2022 decreased as compared to 2021. The change was primarily due to minimal acquisition activity and lower net oil and gas capital expenditures in 2022 compared to the same period in 2021.

Financing Activities. Cash flows used in financing activities for 2022 increased as compared to 2021. The increase was primarily due to higher distributions paid to common unitholders as well as higher net repayments under our Credit Facility in 2022 compared with 2021.

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 2023 capital expenditure budget associated with our non-operated working interests is expected to be approximately $6.9 million, net of farmout reimbursements. The majority of this capital is anticipated to be spent on a well in the Austin Chalk play and the remaining will be spent for workovers and recompletions on existing wells in which we own a working interest in the Shelby Trough play.

We spent approximately $0.6 million and $4.2 million associated with our non-operated working interests, net of farmout reimbursements during 2022 and 2021, respectively.

Acquisitions

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, and is derived from the value of our oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. We and the lenders (at the direction of two-thirds of the lenders) each have discretion to request a borrowing base redetermination one time between scheduled redeterminations. We also have the right to request a redetermination following the acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition. The borrowing base is also adjusted if we terminate our hedge positions or sell oil and natural gas property interests that have a combined value exceeding 5% of the current borrowing base. In these circumstances, the borrowing base will be adjusted by the value attributed to the terminated hedge positions or the oil and natural gas property interests sold in the most recent borrowing base. The April and October 2021 and April 2022 borrowing base redeterminations reaffirmed the borrowing base at $400.0 million. In October 2022, we 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 we elected to lower commitments under the Credit Facility from $400.0 million to $375.0 million. The next semi-annual redetermination is scheduled for April 2023.

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

We are obligated to pay a quarterly commitment fee ranging from a 0.375% to 0.500% annualized rate on the unused portion of the borrowing base, depending on the amount of the borrowings outstanding in relation to the borrowing base.

Principal may be optionally repaid from time to time without premium or penalty, other than customary 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. Our Credit Facility is secured by substantially all of our oil and natural gas production and assets.

Our credit agreement contains various affirmative, negative, and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates, and entering into certain derivative agreements, as well as require the maintenance of certain financial ratios. The credit agreement contains two financial covenants: total debt to EBITDAX of 3.5:1.0 or less and a current ratio of 1.0:1.0 or greater as defined in the credit agreement. Distributions are not permitted if there is a default under the credit agreement (including the failure to satisfy one of the financial covenants), if the availability under the Credit Facility is less than 10% of the lenders' commitments, or if total debt to EBITDAX is greater than 3.0. The lenders have the right to accelerate all of the indebtedness under the credit agreement upon the occurrence and during the continuance of any event of default, and the credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. As of December 31, 2022, we were in compliance with all debt covenants.

Contractual Obligations

The following table summarizes our minimum payments as of December 31, 2022 (in thousands):

		Payments due by period			
	Total	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Credit facility	$ 10,000	$ —	$ —	$ 10,000	$ —
Operating lease obligations	3,726	818	2,399	509	—
Purchase commitments	537	430	107	—	—
Total	$ 14,263	$ 1,248	$ 2,506	$ 10,509	$ —

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.

Please read the notes to the consolidated financial statements included elsewhere in this Annual Report for additional information regarding our accounting policies.

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. Other items subject to significant estimates and assumptions include the carrying amount of oil and natural gas properties, valuation of commodity derivative financial instruments, determination of revenue accruals, and the determination of the fair value of equity-based awards.

We evaluate estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. A significant decline in oil or natural gas prices could 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 $47.2 million, $60.4 million, and $81.3 million for the years ended December 31, 2022, 2021, and 2020, 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 a collapse in oil prices during the first quarter of 2020 due to geopolitical events that increased supply at the same time demand weakened due to the impact of the COVID-19 pandemic. The Partnership determined these events and circumstances indicated a possible decline in the recoverability of the carrying value of certain proved properties and recoverability testing determined that certain depletable units consisting of mature oil producing properties were impaired. There was no impairment of proved oil and natural gas properties for the years ended December 31, 2022 and 2021. We recognized $51.0 million of impairment of proved oil and natural gas properties for the year ended December 31, 2020.

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, 2022, 2021, and 2020.

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, 2022 reserve report. Applying this discount results in an approximate 0.7% reduction of estimated proved reserve volumes as compared to the undiscounted pricing scenario used in our December 31, 2022 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.

Lease bonus and other income

We also earn revenue from lease bonuses and delay rentals. We generate lease bonus revenue by leasing mineral interests to exploration and production companies. A lease agreement represents our contract with a customer and generally transfers the rights to any oil or natural gas discovered, grants us 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 we have satisfied our performance obligation when the lease agreement is executed, such that revenue is recognized when the lease bonus payment is received. At the time we execute the lease agreement, we expect to receive the lease bonus payment within a reasonable time, though in no case more than one year, such that we have not adjusted the expected amount of consideration for the effects of any significant financing component per the practical expedient in ASC 606. We also recognize revenue from delay rentals to the extent drilling has not started within the specified period, payment has been received, and we have no further obligation to refund the payment.

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.

Lease bonus and other income

Given that we do 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, we do not record revenue for unsatisfied or partially unsatisfied performance obligations as of the end of the reporting period.

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, 2022 and 2021, revenue recognized in the reporting periods related to performance obligations satisfied in prior reporting periods was immaterial.

Commodity Derivative Financial Instruments

Our ongoing operations expose us to changes in the market price for oil and natural gas. To mitigate the given price risk associated with our operations, we use 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. We do not enter into derivative instruments for speculative purposes. The impact of these derivative instruments could affect the amount of revenue we ultimately record.

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. Gains and losses arising from changes in the fair value of derivatives are recognized on a net basis in the accompanying consolidated statements of operations within gain (loss) on commodity derivative instruments. Although these derivative instruments may expose us to credit risk, we monitor the creditworthiness of our counterparties.

Equity-Based Compensation

We recognize equity-based compensation expense for unit-based awards granted to our employees and the Board. Total compensation expense for unit-based awards is calculated based on the number of units multiplied by the grant-date fair value per unit. Compensation expense for time-based restricted unit awards with graded vesting requirements are recognized using straight-line attribution over the requisite service period. Compensation expense related to the restricted performance unit awards is determined by multiplying the number of common units underlying such awards 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. Equity-based compensation expense related to unit-based awards is included in General and administrative expense within the consolidated statements of operations. Distribution equivalent rights for the restricted performance unit awards are charged to partners’ capital. Please read Note 9 – Incentive Compensation within the consolidated financial statements included elsewhere in this Annual Report for additional information.

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, 2022. Applying this discount results in an approximate 0.7% reduction of proved reserve volumes as compared to the undiscounted December 31, 2022 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, 2022, we had seven counterparties, all of which are rated Baa1 or better by Moody's and are lenders under our Credit Facility.

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

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. As of December 31, 2022, we had $10.0 million of outstanding borrowings under our Credit Facility, bearing interest at a weighted-average interest rate of 6.92%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of $0.1 million for the year ended December 31, 2022, 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, 2022 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, 2022, 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, 2022.

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, 2022, which is included in the Annual Report on page F-4.

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, 2022, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Information required by this item is incorporated by reference to the material appearing in our Proxy Statement for the 2023 Annual Meeting of Limited Partners ("2023 Proxy Statement"), which will be filed with the SEC not later than 120 days after December 31, 2022.

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 2023 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2022.

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 2023 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2022.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to the 2023 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2022.

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 2023 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2022.

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 (incorporated herein by reference to Exhibit 10.13 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on April 13, 2015 (SEC File No. 333-202875)).
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
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
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)).

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
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 22, 2023

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.	Chief Executive Officer and Chairman (Principal Executive Officer)	February 22, 2023
/s/ Jeffrey P. Wood Jeffrey P. Wood	President and Chief Financial Officer (Principal Financial Officer)	February 22, 2023
/s/ Dawn K. Smajstrla Dawn K. Smajstrla	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 22, 2023
/s/ Carin M. Barth Carin M. Barth	Director	February 22, 2023
/s/ D. Mark DeWalch D. Mark DeWalch	Director	February 22, 2023
/s/ Jerry V. Kyle, Jr. Jerry V. Kyle, Jr.	Director	February 22, 2023
/s/ Michael C. Linn Michael C. Linn	Director	February 22, 2023
/s/ John H. Longmaid John H. Longmaid	Director	February 22, 2023
/s/ William N. Mathis William N. Mathis	Director	February 22, 2023
/s/ William E. Randall William E. Randall	Director	February 22, 2023
/s/ Alexander D. Stuart Alexander D. Stuart	Director	February 22, 2023
/s/ Allison K. Thacker Allison K. Thacker	Director	February 22, 2023

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, 2022 and 2021, the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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, 2022, 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 22, 2023, 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, 2022, the net book value of the Partnership's oil and natural gas properties was $1,087 million, and depreciation, depletion and amortization ("DD&A") expense related to the Partnership's oil and natural gas properties was $47 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 estimated by independent petroleum engineers. Leasehold acquisition costs and costs to acquire proved properties are amortized on the basis of total proved reserves, also estimated 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. Significant judgment is required by the independent petroleum engineers in interpreting geological and engineering data used to estimate proved oil and natural gas reserves. Estimating proved oil and natural gas reserves also requires the selection of inputs, including 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, 2022. Auditing the Partnership's 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 estimating 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 DD&A, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating 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 completeness and accuracy of the financial data and inputs described above used by the engineers in estimating proved oil and natural gas reserves by evaluating corroborative and contrary evidence. We also tested the mathematical accuracy of the 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, 2022, the Partnership had $129 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 22, 2023

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, 2022, 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, 2022, 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, 2022 and 2021, the related consolidated statements of operations, equity, and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and our report dated February 22, 2023, 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 22, 2023

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

	As of December 31,	
	2022	2021
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4,307	$ 8,876
Accounts receivable	135,697	97,142
Commodity derivative assets	31,472	—
Prepaid expenses and other current assets	1,905	1,956
TOTAL CURRENT ASSETS	173,381	107,974
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $909,344 and $937,395 at December 31, 2022 and 2021, respectively	3,003,907	3,001,627
Accumulated depreciation, depletion, amortization, and impairment	(1,916,919)	(1,869,731)
Oil and natural gas properties, net	1,086,988	1,131,896
Other property and equipment, net of accumulated depreciation of $13,461 and $12,931 at December 31, 2022 and 2021, respectively	1,259	1,440
NET PROPERTY AND EQUIPMENT	1,088,247	1,133,336
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	9,454	6,611
TOTAL ASSETS	$ 1,271,082	$ 1,247,921
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 6,773	$ 5,944
Accrued liabilities	19,729	17,589
Commodity derivative liabilities	3,243	51,544
Other current liabilities	989	2,063
TOTAL CURRENT LIABILITIES	30,734	77,140
LONG-TERM LIABILITIES		
Credit facility	10,000	89,000
Accrued incentive compensation	1,884	838
Commodity derivative liabilities	16	2,001
Asset retirement obligations	15,030	12,561
Other long-term liabilities	3,606	2,752
TOTAL LIABILITIES	61,270	184,292
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, 2022 and 2021, respectively	298,361	298,361
EQUITY		
Partners' equity — general partner interest	—	—
Partners' equity — common units, 209,407 and 208,666 units outstanding at December 31, 2022 and 2021, respectively	911,451	765,268
TOTAL EQUITY	911,451	765,268
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,271,082	$ 1,247,921

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,		
	2022	**2021**	**2020**
REVENUE			
Oil and condensate sales	$ 336,287	$ 235,771	$ 148,631
Natural gas and natural gas liquids sales	434,945	255,671	138,926
Lease bonus and other income	13,052	14,292	9,083
Revenue from contracts with customers	784,284	505,734	296,640
Gain (loss) on commodity derivative instruments	(120,680)	(146,474)	46,111
TOTAL REVENUE	663,604	359,260	342,751
OPERATING (INCOME) EXPENSE			
Lease operating expense	12,380	13,056	14,022
Production costs and ad valorem taxes	66,233	49,809	43,473
Exploration expense	193	1,082	29
Depreciation, depletion, and amortization	47,804	61,019	82,018
Impairment of oil and natural gas properties	—	—	51,031
General and administrative	53,652	48,746	42,983
Accretion of asset retirement obligations	861	1,073	1,131
(Gain) loss on sale of assets, net	(17)	(2,850)	(24,045)
TOTAL OPERATING EXPENSE	181,106	171,935	210,642
INCOME (LOSS) FROM OPERATIONS	482,498	187,325	132,109
OTHER INCOME (EXPENSE)			
Interest and investment income	53	1	35
Interest expense	(6,286)	(5,638)	(10,408)
Other income (expense)	215	299	83
TOTAL OTHER EXPENSE	(6,018)	(5,338)	(10,290)
NET INCOME (LOSS)	476,480	181,987	121,819
Distributions on Series B cumulative convertible preferred units	(21,000)	(21,000)	(21,000)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 455,480	$ 160,987	$ 100,819
ALLOCATION OF NET INCOME (LOSS):			
General partner interest	$ —	$ —	$ —
Common units	455,480	160,987	100,819
	$ 455,480	$ 160,987	$ 100,819
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:			
Per common unit (basic)	$ 2.18	$ 0.77	$ 0.49
Per common unit (diluted)[1]	$ 2.12	$ 0.77	$ 0.49
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:			
Weighted average common units outstanding (basic)	209,382	208,181	206,705
Weighted average common units outstanding (diluted)	224,446	208,290	206,819

[1] For the year ended December 31, 2022 diluted net income (loss) attributable to common units included distributions on Series B cumulative convertible preferred units of $21 million.

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, 2019	205,960	$ 798,443	$ 798,443
Conversion of Series A redeemable preferred units			
Repurchases of common units	(503)	(5,035)	(5,035)
Restricted units granted, net of forfeitures	1,292	—	—
Equity-based compensation	—	7,118	7,118
Distributions	—	(140,343)	(140,343)
Charges to partners' equity for accrued distribution equivalent rights	—	(396)	(396)
Distributions on Series B cumulative convertible preferred units	—	(21,000)	(21,000)
Net income (loss)	—	121,819	121,819
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

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,		
	2022	**2021**	**2020**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 476,480	$ 181,987	$ 121,819
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	47,804	61,019	82,018
Impairment of oil and natural gas properties	—	—	51,031
Accretion of asset retirement obligations	861	1,073	1,131
Amortization of deferred charges	1,954	1,579	1,044
(Gain) loss on commodity derivative instruments	120,680	146,474	(46,111)
Net cash (paid) received on settlement of commodity derivative instruments	(203,166)	(112,946)	81,349
Equity-based compensation	17,388	12,218	3,727
Exploratory dry hole expense	—	1,048	—
(Gain) loss on sale of assets, net	(17)	(2,850)	(24,045)
Changes in operating assets and liabilities:			
Accounts receivable	(39,513)	(34,856)	16,494
Prepaid expenses and other current assets	51	(289)	(500)
Accounts payable, accrued liabilities, and other	3,012	2,652	(5,929)
Settlement of asset retirement obligations	(551)	(229)	(219)
NET CASH PROVIDED BY OPERATING ACTIVITIES	424,983	256,880	281,809
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisitions of oil and natural gas properties	(149)	(10,043)	(28)
Additions to oil and natural gas properties	(11,894)	(4,066)	(3,969)
Additions to oil and natural gas properties leasehold costs	(32)	(98)	(798)
Purchases of other property and equipment	(488)	(428)	(21)
Proceeds from the sale of oil and natural gas properties	17	318	151,864
Proceeds from farmouts of oil and natural gas properties	11,331	—	4,198
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	(1,215)	(14,317)	151,246
CASH FLOWS FROM FINANCING ACTIVITIES			
Distributions to common and subordinated unitholders	(322,403)	(176,924)	(140,343)
Distributions to Series B cumulative convertible preferred unitholders	(21,000)	(21,000)	(21,000)
Repurchases of common and subordinated units	(2,991)	(1,957)	(5,035)
Borrowings under credit facility	339,000	212,000	160,000
Repayments under credit facility	(418,000)	(244,000)	(433,000)
Debt issuance costs and other	(2,943)	(3,602)	—
NET CASH (USED IN) PROVIDED BY FINANCING ACTIVITIES	(428,337)	(235,483)	(439,378)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(4,569)	7,080	(6,323)
Cash and cash equivalents — beginning of the year	8,876	1,796	8,119
Cash and cash equivalents — end of the year	$ 4,307	$ 8,876	$ 1,796
SUPPLEMENTAL DISCLOSURE			
Interest paid	$ 4,332	$ 4,035	$ 9,449

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 significant 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,	
	2022	2021
	(in thousands)	
Accounts receivable:		
Revenues from contracts with customers	$ 129,078	$ 93,005
Other	6,619	4,137
Total accounts receivable	$ 135,697	$ 97,142

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 further discussion.

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 further discussion.

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 $47.2 million, $60.4 million, and $81.3 million for the years ended December 31, 2022, 2021, and 2020, respectively.

The Partnership evaluates 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. 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. There was a collapse in oil prices during the first quarter of 2020 due to geopolitical events that increased supply at the same time demand weakened due to the impact of the COVID-19 pandemic. The Partnership determined these events and circumstances indicated a possible decline in the recoverability of the carrying value of certain proved properties and recoverability testing determined that certain depletable units consisting of mature oil producing properties were impaired. There was no impairment of proved oil and natural gas properties for the years ended December 31, 2022 and 2021. The Partnership recognized $51.0 million of impairment of proved oil and natural gas properties for the year ended December 31, 2020. See Note 6 - Fair Value Measurements for further discussion.

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, 2022, 2021, and 2020.

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 $0.6 million, $0.6 million, and $0.7 million for the years ended December 31, 2022, 2021, and 2020, 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,	
	2022	2021
	(in thousands)	
Accrued liabilities:		
Accrued capital expenditures	$ 162	$ 849
Accrued incentive compensation	10,050	8,978
Accrued property taxes	7,431	5,704
Accrued other	2,086	2,058
Total accrued liabilities	$ 19,729	$ 17,589

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 $2.0 million, $1.6 million, and $1.0 million for the years ended December 31, 2022, 2021, and 2020, 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, 2022 and 2021, 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, 2022 and 2021, 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, 2022 and 2021 due to the short-term maturity of these instruments. See Note 6 – Fair Value Measurements for further discussion.

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 discussion.

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,	
	2022	2021
	(in thousands)	
Beginning asset retirement obligations	$ 13,284	$ 17,717
Liabilities incurred	124	463
Liabilities settled	(294)	(351)
Accretion expense	861	1,073
Revisions in estimated costs	2,044	45
Dispositions	—	(5,663)
Ending asset retirement obligations	$ 16,019	$ 13,284
Current asset retirement obligations	$ 989	$ 723
Non-current asset retirement obligations	$ 15,030	$ 12,561

NOTE 4 — OIL AND NATURAL GAS PROPERTIES

Divestitures

The Partnership had no material divestiture activity during 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.

In the third quarter of 2020, the Partnership closed two separate divestitures of certain mineral and royalty properties in the Permian Basin for total proceeds, after final closing adjustments, of $150.6 million. One of these transactions, effective May 1, 2020, involved the sale of the Partnership's mineral and royalty interest in specific tracts in Midland County, Texas for net proceeds of approximately $54.5 million. The other transaction, effective July 1, 2020, involved the sale of an undivided interest across parts of the Partnership's Delaware Basin and Midland Basin positions for net proceeds of approximately $96.1 million. The total book value of the assets divested through these transactions was $126.6 million at the time of sale. The Partnership recognized a $24.0 million gain associated with the divestitures included in the (Gain) loss on sale of assets, net line item of the consolidated statement of operations for the year ended December 31, 2020.

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.

The Partnership had no material acquisition activity during 2022 and 2020.

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.

In 2017, the Partnership entered into farmout arrangements with Canaan Resource Partners ("Canaan") and Pivotal Petroleum Partners ("Pivotal") in the Shelby Trough area of East Texas where the Partnership owns a concentrated, relatively high-interest royalty position. This area was under active development by XTO Energy Inc. ("XTO") in San Augustine County, Texas and BPX Energy in Angelina County, Texas through 2019. These farmout agreements were superseded and replaced by the new farmout agreements discussed below.

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, ten wells to be drilled in the second and third program years, and, thereafter, a minimum of twelve 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 ten 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, 2022, ten 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, ten wells to be drilled in the second program year, and, beginning with the third program year, fifteen 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, 2022, a total of eighteen wells have been spud in the contract area subject to the Pivotal Farmout.

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.

There was a collapse in oil prices during the first quarter of 2020 due to geopolitical events that increased supply at the same time demand weakened due to the impact of the COVID-19 pandemic. The Partnership determined these events and circumstances indicated a possible decline in the recoverability of the carrying value of certain proved properties and recoverability testing determined that certain depletable units consisting of mature oil producing properties were impaired. No impairment of oil and natural gas properties was recognized for the years ended December 31, 2022 and 2021. The Partnership recognized impairment of oil and natural gas properties of $51.0 million for the year ended December 31, 2020. See Note 6 - Fair Value Measurements for further discussion.

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, 2022 and 2021, 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, 2022 and 2021. See Note 6 – Fair Value Measurements for further discussion.

The Partnership's derivative contracts expose it to credit risk in the event of nonperformance by counterparties that may adversely impact the fair value of the Partnership's commodity derivative assets. While the Partnership does not require its derivative contract counterparties to post collateral, the Partnership does evaluate the credit standing of such counterparties as deemed appropriate. This evaluation includes reviewing a counterparty’s credit rating and latest financial information. As of December 31, 2022, the Partnership had seven counterparties, all of which are rated Baa1 or better by Moody’s and are lenders under the Credit Facility.

The tables below summarize the fair 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, 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

		As of December 31, 2021		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ —	$ —	$ —
Long-term asset	Deferred charges and other long-term assets	—	—	—
Total assets		$ —	$ —	$ —
Liabilities:				
Current liability	Commodity derivative liabilities	$ 51,544	$ —	$ 51,544
Long-term liability	Commodity derivative liabilities	2,001	—	2,001
Total liabilities		$ 53,545	$ —	$ 53,545

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	**2022**	**2021**	**2020**
		(in thousands)	
Beginning fair value of commodity derivative instruments	$ (53,545)	$ (20,017)	$ 15,221
Gain (loss) on oil derivative instruments	(46,890)	(75,180)	36,091
Gain (loss) on natural gas derivative instruments	(73,790)	(71,294)	10,020
Net cash paid (received) on settlements of oil derivative instruments	77,790	66,418	(56,487)
Net cash paid (received) on settlements of natural gas derivative instruments	125,376	46,528	(24,862)
Net change in fair value of commodity derivative instruments	82,486	(33,528)	(35,238)
Ending fair value of commodity derivative instruments	$ 28,941	$ (53,545)	$ (20,017)

The Partnership had the following open derivative contracts for oil as of December 31, 2022:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (per Bbl)	Range (per Bbl)	
			Low	High
Oil Swap Contracts:				
2022				
Fourth quarter	220,000	$ 66.47	$ 55.29	$ 83.91
2023				
First quarter	630,000	79.44	73.00	85.93
Second quarter	540,000	80.80	73.00	89.50
Third quarter	540,000	80.80	73.00	89.50
Fourth quarter	540,000	80.80	73.00	89.50

The Partnership had the following open derivative contracts for natural gas as of December 31, 2022:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (per MMBtu)	Range (per MMBtu)	
			Low	High
Natural Gas Swap Contracts:				
2023				
First quarter	9,000,000	$ 5.07	$ 3.28	$ 6.59
Second quarter	8,190,000	5.15	3.28	6.59
Third quarter	8,280,000	5.15	3.28	6.59
Fourth quarter	8,280,000	5.15	3.28	6.59

The Partnership entered into the following derivative contracts for natural gas subsequent to December 31, 2022:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (per MMBtu)	Range (per MMBtu)	
			Low	High
Natural Gas Swap Contracts:				
2024				
First quarter	3,640,000	3.67	3.57	3.76
Second quarter	3,640,000	3.67	3.57	3.76
Third quarter	3,680,000	3.67	3.57	3.76
Fourth quarter	3,680,000	3.67	3.57	3.76

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, 2022 and 2021.

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, 2022 and 2021 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 further discussion.

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

	Fair Value Measurements Using			Effect of	
	Level 1	Level 2	Level 3	Counterparty Netting	Total
			(in thousands)		
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
As of December 31, 2021					
Financial Assets					
Commodity derivative instruments	$ —	$ —	$ —	$ —	$ —
Financial Liabilities					
Commodity derivative instruments	—	53,545	—	—	53,545

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. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, and a risk-adjusted discount rate. The Partnership estimated the fair value of the impaired properties using published forward commodity price curves as of the measurement date of March 31, 2020, considering locational and quality differentials based on a review of historical realizations, and using an annual discount rate of 8%.

	Fair Value Measurements Using			
	Level 1	Level 2	Level 3	Impairment
	(in thousands)			
Year Ended December 31, 2022				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —
Year Ended December 31, 2021				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —
Year Ended December 31, 2020				
Impaired oil and natural gas properties	$ —	$ —	$ 2,044	$ 51,031

The Partnership’s estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. Changes to these estimates, particularly related to economic reserves, future commodity prices, and timing of future production could result in additional impairment charges in the future. There were no significant changes in valuation techniques or related inputs for the years ended December 31, 2022 and 2021. There were no assets measured at fair value on a non-recurring basis, after initial recognition, for the years ended 2022 and 2021.

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%, 19%, and 20% of total oil and natural gas revenue for the years ended December 31, 2022, 2021, and 2020, respectively.

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. The April and October 2021 and April 2022 borrowing base redeterminations reaffirmed the borrowing base at $400.0 million. 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 next semi-annual redetermination is scheduled for April 2023.

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 ½ of 1.00%, 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, 2021 the applicable margin for the alternative base rate ranged from 1.50% and 2.50% and the applicable margin for LIBOR ranged from 2.50% and 3.50% depending on the borrowings outstanding in relation to the borrowing base. As of December 31, 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 weighted-average interest rate of the Credit Facility was 6.92% and 2.61% as of December 31, 2022 and 2021, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% per annum if the borrowing base utilization percentage is equal to or greater than 50%. The Credit Facility is secured by substantially all of the Partnership’s oil and natural gas production and assets.

The Credit Facility contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Credit Facility requires the Partnership to maintain a current ratio of not less than 1.0:1.0 and a ratio of total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization, and Exploration) of not more than 3.5:1.0. Distributions are not permitted if there is a default under the credit 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, 2022, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $10.0 million and $89.0 million at December 31, 2022 and 2021, respectively. The unused portion of the available borrowings under the Credit Facility were $365.0 million and $311.0 million at December 31, 2022 and 2021, 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 2022 grant includes restricted common units subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through January 7, 2025. 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, 2022.

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2021	761,992	$ 10.47
Granted	418,582	12.00
Vested	(354,156)	11.68
Forfeited	(3,140)	11.99
Unvested at December 31, 2022	823,278	10.72

The weighted-average grant-date fair value per unit for unit-based awards was $12.00, $9.25, and $9.97 for the years ended December 31, 2022, 2021, and 2020, respectively. As of December 31, 2022, unrecognized compensation cost associated with restricted unit awards was $4.8 million, which the Partnership expects to recognize over a weighted-average period of 1.71 years. The fair value of units vested for the years ended December 31, 2022, 2021, and 2020 was $4.0 million, $2.3 million, and $7.5 million, respectively. There were no cash payments made for vested units during the years ended December 31, 2022, 2021, and 2020.

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, 2022.

Performance units	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2021	1,062,487	$ 11.68
Granted[1]	454,688	12.40
Vested	(338,506)	17.09
Forfeited	(3,140)	11.99
Unvested at December 31, 2022	1,175,529	10.40

[1] Includes 36,106 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 $12.40, $9.61, and $10.95 for the years ended December 31, 2022, 2021, and 2020, respectively. Unrecognized compensation cost associated with performance unit awards was $8.2 million as of December 31, 2022, which the Partnership expects to recognize over a weighted-average period of 1.62 years. The fair value of performance units vested for the years ended December 31, 2022, 2021 and 2020 was $3.9 million, $2.8 million and $5.5 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, 2022.

Aspirational Performance units	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2021	—	$ —
Granted	1,476,943	11.58
Vested	—	—
Forfeited	(64,935)	11.55
Unvested at December 31, 2022	1,412,008	11.58

Total compensation expense to be recognized over the life of the Aspirational Awards consists of $5.2 million for the performance cash awards and $16.4 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, 2022, 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, 2022, 2021, and 2020.

Incentive compensation expense	Year Ended December 31, 2022	2021	2020
	(in thousands)		
Cash — short and long-term incentive plan	$ 7,095	$ 6,824	$ 2,962
Equity-based compensation — restricted common units	4,089	4,146	4,688
Equity-based compensation — restricted performance units	11,174	6,320	(2,417)
Board of Directors incentive plan	2,125	1,752	1,456
Total incentive compensation expense	$ 24,483	$ 19,042	$ 6,689

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, $0.5 million, and $0.5 million for the years ended December 31, 2022, 2021, and 2020, 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, 2022 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 $20.3926 per Series B cumulative convertible preferred unit, resulting in total proceeds of approximately $300 million.

The Series B cumulative convertible preferred units are entitled to quarterly distributions in an amount equal to 7.0% of the face amount of the preferred units per annum (the “Distribution Rate”), provided that the Distribution Rate will be adjusted as follows: commencing on November 28, 2023 and readjusting every two years thereafter (each, a “Readjustment Date”), the rate will equal 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 $20.3926, adjusted to give effect to any accrued but unpaid accumulated distributions on the applicable Series B cumulative convertible preferred units through the most recent declaration date. However, the Partnership shall not be obligated to honor any request for such conversion if such request does not involve an underlying value of common units of at least $10.0 million based on the closing trading price of common units on the trading day immediately preceding the conversion notice date, or such lesser amount to the extent such exercise covers all of a holder's Series B cumulative convertible preferred units.

The Series B cumulative convertible preferred units had a carrying value of $298.4 million, including accrued distributions of $5.3 million, as of December 31, 2022 and 2021. 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.

The Partnership has the option to redeem the Series B cumulative convertible preferred units for a 90 day period beginning on November 28, 2023 at a redemption price of $21.41 per Series B cumulative convertible preferred unit. 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.

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,		
	2022	2021	2020
	(in thousands, except per unit amounts)		
NET INCOME (LOSS)	$ 476,480	$ 181,987	$ 121,819
Distributions on Series B cumulative convertible preferred units	(21,000)	(21,000)	(21,000)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 455,480	$ 160,987	$ 100,819
ALLOCATION OF NET INCOME (LOSS):			
General partner interest	$ —	$ —	$ —
Common units	455,480	160,987	100,819
	$ 455,480	$ 160,987	$ 100,819
Weighted average common units outstanding:			
Weighted average common units outstanding (basic)	209,382	208,181	206,705
Effect of dilutive securities	15,064	109	114
Weighted average common units outstanding (diluted)	224,446	208,290	206,819
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:			
Per common unit (basic)	$ 2.18	$ 0.77	$ 0.49
Per common unit (diluted)[1]	2.12	0.77	0.49

[1] For the year ended December 31, 2022 diluted net income (loss) attributable to common units included distributions on Series B cumulative convertible preferred units of $21 million.

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

	For the Year Ended December 31,		
	2022	2021	2020
	(in thousands)		
Potentially dilutive securities (common units):			
Series B cumulative convertible preferred units on an as-converted basis	—	14,968	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% per annum, subject to certain adjustments; and
- *second*, to the holders of common units.

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

	Year Ended December 31,		
	2022	2021	2020
Distributions declared and paid per common unit	$ 1.54	$ 0.85	$ 0.68

NOTE 15 — SUBSEQUENT EVENTS

Leadership Change

On January 18, 2023, the Partnership announced that Jeff Wood, the President, Chief Financial Officer, and Treasurer of the Partnership's general partner, will leave the Partnership effective February 28, 2023. Upon Mr. Wood's departure, Evan Kiefer, who currently serves as Vice President, Finance and Investor Relations, will assume the role of Interim Chief Financial Officer and Treasurer. The Partnership does not expect Mr. Wood's departure to have a material impact on its operations.

Distribution

On February 1, 2023, the Board approved a distribution for the period from October 1, 2022 to December 31, 2022 of $0.475 per common unit. Distributions will be paid on February 23, 2023 to unitholders of record at the close of business on February 16, 2023.

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,		
	2022	2021	2020
	(in thousands)		
Acquisition Costs of Properties[1]:			
Proved	$ —	$ 4,965	$ —
Unproved	149	15,559	28
Exploration Costs	—	1,049	—
Development Costs[1]	11,293	3,964	2,742
Total	$ 11,442	$ 25,537	$ 2,770

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

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,	
	2022	2021
	(in thousands)	
Proved properties	$ 2,094,563	$ 2,064,232
Unproved properties	909,344	937,395
Total	3,003,907	3,001,627
Accumulated depreciation, depletion, amortization, and impairment	(1,916,919)	(1,869,731)
Oil and natural gas properties, net	$ 1,086,988	$ 1,131,896

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 $94.14, $66.55, and $39.54 per barrel as of December 31, 2022, 2021, and 2020, 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 $6.36, $3.60, and $1.99 per MMBTU as of December 31, 2022, 2021, and 2020, 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 $92.01 per barrel for oil and $6.50 per Mcf for natural gas as of December 31, 2022, $63.17 per barrel for oil and $3.37 per Mcf for natural gas as of December 31, 2021, and $36.43 per barrel for oil and $1.60 per Mcf for natural gas as of December 31, 2020.

	Crude Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)
Net proved reserves at December 31, 2019	17,050	308,958	68,543
Revisions of previous estimates [1]	2,490	(22,337)	(1,233)
Sales of minerals in place[4]	(1,262)	(3,132)	(1,784)
Extensions, discoveries and other additions[3]	1,569	24,667	5,680
Production	(3,895)	(67,945)	(15,219)
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
Net Proved Developed Reserves			
December 31, 2020	15,952	230,411	54,354
December 31, 2021	19,111	224,222	56,481
December 31, 2022	19,184	236,529	58,606
Net Proved Undeveloped Reserves			
December 31, 2020	—	9,800	1,633
December 31, 2021	60	19,695	3,343
December 31, 2022	—	33,057	5,509

[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 in 2020 are related to a reduction of royalty on certain Haynesville/Bossier wells in order to incentivize the operator to complete and turn the wells to sales. The most notable revisions in 2022 and 2021 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 within multiple basins.

[4] Includes divestitures of mineral and royalty reserves. In 2020 these were primarily in the Permian Basin and 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 further discussion.

	Year Ended December 31,		
	2022	2021	2020
	(in thousands)		
Future cash inflows	$ 3,518,494	$ 2,033,256	$ 965,007
Future production costs	(339,603)	(206,785)	(99,124)
Future development costs	(49,081)	(43,500)	(59,692)
Future income tax expense	(10,535)	(6,322)	(3,019)
Future net cash flows (undiscounted)	3,119,275	1,776,649	803,172
Annual discount 10% for estimated timing	(1,454,264)	(804,527)	(309,675)
Total	$ 1,665,011	$ 972,122	$ 493,497

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

	Year Ended December 31,		
	2022	2021	2020
	(in thousands)		
Standardized measure, beginning of year	$ 972,122	$ 493,497	$ 847,894
Sales, net of production costs	(692,629)	(428,577)	(230,062)
Net changes in prices and production costs related to future production	773,189	537,659	(242,634)
Extensions, discoveries and improved recovery, net of future production and development costs	476,342	148,732	65,903
Previously estimated development costs incurred during the period	854	245	—
Revisions of estimated future development costs	(1,986)	2,254	(1,530)
Revisions of previous quantity estimates, net of related costs	68,270	210,039	(24,195)
Accretion of discount	97,553	49,530	85,109
Purchases of reserves in place, less related costs	—	9,254	—
Sales of reserves in place	—	(1,037)	(26,795)
Changes in timing and other	(28,704)	(49,474)	19,807
Net increase (decrease) in standardized measures	692,889	478,625	(354,397)
Standardized measure, end of year	$ 1,665,011	$ 972,122	$ 493,497

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.

BLACK STONE MINERALS, L.P.
LONG-TERM INCENTIVE PLAN

LTI AWARD GRANT NOTICE

Pursuant to the terms and conditions of the Black Stone Minerals, L.P. Long-Term Incentive Plan, as amended from time to time (the "Plan"), Black Stone Minerals GP, L.L.C., a Delaware limited liability company (the "General Partner"), hereby grants to the individual listed below ("you" or "Employee") the number of performance-based Phantom Units (the "Performance Units") set forth below. This award of Performance Units (this "Award") is subject to the terms and conditions set forth herein as well as the terms and conditions set forth in the LTI Award Agreement attached hereto as Exhibit A (the "Agreement") and in the Plan, each of which is incorporated herein by reference. Capitalized terms used but not defined herein shall have the meanings set forth in the Plan.

Employee:	[[FIRSTNAME]] [[MIDDLENAME]] [[LASTNAME]]
Date of Grant:	[[GRANTDATE]]
Employer:	Black Stone Natural Resources Management Company or any other entity that may employ Employee after the Date of Grant and which entity is the General Partner, Black Stone Minerals, L.P., a Delaware limited partnership (the "Partnership"), or any of their respective Affiliates.
Target Performance Units:	[[SHARESGRANTED]] Performance Units (the "Target Amount Performance Units")
Performance Period:	[●] through [●]
Earning of Performance Units:	Subject to the terms and conditions set forth herein, in the Agreement and in the Plan, the Performance Units shall become earned in the manner set forth below so long as you remain continuously employed by the Employer from the Date of Grant through the end of the Performance Period. The number of Performance Units, if any, that become earned in the Performance Period will be determined in accordance with the following table (the "Performance Goals"):

	Below Threshold	**Threshold**	**Target**	**Maximum**
Average Performance Percentage	< 70%	70%	100%	130%
Percentage of Target Amount Performance Units that are Earned*	0%	50%	100%	200%

*If the Average Performance Percentage is between the Threshold amount and the Target amount set forth in the first row of the table above, then the percentage of the Target Amount Performance Units that are earned shall be determined by linear interpolation between Threshold (50%) and Target (100%) based on the Average Performance Percentage. If the Average Performance Percentage is between the Target amount and the Maximum amount set forth in the first row of the table above, then the percentage of the Target Amount Performance Units that are earned shall be determined by linear interpolation between Target (100%) and Maximum (200%) based on the Average Performance Percentage. Each percentage of Target Amount Performance Units that are earned as determined by linear interpolation shall be rounded to four decimal places.
As used herein, the following terms have the meanings set forth below:

"Average Performance Percentage" means, except as otherwise provided in the Agreement with respect to a Qualifying Termination, the average of the Production Performance Percentage and the Reserve Performance Percentage for the three Performance Period Years in the Performance Period.

"BOE" means a barrel of oil equivalent that is one barrel (42 US gallons) of crude oil or six thousand (6,000) cubic feet of natural gas.

"Budget" means, with respect to a Performance Period Year, the annual budget adopted by the Board for such Performance Period Year.

"Performance Period Year" means each calendar year during the Performance Period.

"Production Performance Percentage" means, with respect to a Performance Period Year, the quotient of (i) the amount of production (expressed as BOE) achieved by the Partnership and its subsidiaries for such Performance Period Year per weighted average Units outstanding for such Performance Period Year divided by (ii) the Production Target for such Performance Period Year per budgeted weighted average Units outstanding for such Performance Period Year.

"Production Target" means, with respect to a Performance Period Year, the budgeted amount of the Partnership's and its subsidiaries' production (expressed as BOE) for such Performance Period Year set forth in the Budget for such Performance Period Year.

"Reserve Performance Percentage" means, with respect to a Performance Period Year, the quotient of (i) the amount of the Partnership's and its subsidiaries' reserves (expressed as BOE) as of the last day of such Performance Period Year per Units outstanding on the last day of such Performance Period Year divided by (ii) the Reserve Target for such Performance Period Year per budgeted Units outstanding on the last day of such Performance Period Year.

"Reserve Target" means, with respect to a Performance Period Year, the budgeted amount of the Partnership's and its subsidiaries' reserves (expressed as BOE) as of the last day of such Performance Period Year as set forth in the Budget for such Performance Period Year.

"Unit" has the meaning given to it in the Partnership Agreement and shall include the Preferred Units (as defined in the Partnership Agreement) on an as-converted basis.

By clicking to accept, you agree to be bound by the terms and conditions of the Plan, the Agreement and this LTI Award Grant Notice (this "Grant Notice"). You acknowledge that you have reviewed the Agreement, the Plan and this Grant Notice in their entirety and fully understand all provisions of the Agreement, the Plan and this Grant Notice. You hereby agree to accept as binding, conclusive and final all decisions or interpretations of the Committee regarding any questions or determinations arising under the Agreement, the Plan or this Grant Notice.

In lieu of receiving documents in paper format, you agree, to the fullest extent permitted by applicable law, to accept electronic delivery of any documents that the General Partner or any Affiliate may be required to deliver (including prospectuses, prospectus supplements, grant or award notifications and agreements, account statements, annual and quarterly reports, and all other forms of communications) in connection with this and any other award made or offered by the General Partner. Electronic delivery may be made via the electronic mail system of the General Partner or one of its Affiliates or by reference to a location on an intranet site to which you have access. You hereby consent to any and all procedures the General Partner has established or may establish for an electronic signature system for delivery and acceptance of any such documents.

You acknowledge and agree that clicking to accept this Award constitutes your electronic signature and is intended to have the same force and effect as your manual signature.

Remainder of Page Intentionally Blank;
Signature Page Follows

IN WITNESS WHEREOF, the General Partner has caused this Grant Notice to be executed by an officer thereunto duly authorized effective for all purposes as provided above.

BLACK STONE MINERALS GP, L.L.C.

By:________________________________
Steve Putman
Senior Vice President, General Counsel, and Secretary

Signature Page to
LTI Award Grant Notice

EXHIBIT A

LTI AWARD AGREEMENT

This LTI Award Agreement (this "Agreement") is made as of the Date of Grant set forth in the Grant Notice to which this Agreement is attached (the "Date of Grant") by and between Black Stone Minerals GP, L.L.C., a Delaware limited liability company (the "General Partner"), and [[FIRSTNAME]] [[MIDDLENAME]] [[LASTNAME]] ("Employee"). Capitalized terms used but not specifically defined herein shall have the meanings specified in the Plan or the Grant Notice.

1. **Award**. Effective as of the Date of Grant, the General Partner hereby grants to Employee the number of performance-based Phantom Units set forth in the Grant Notice (the "Performance Units") on the terms and conditions set forth in the Grant Notice, this Agreement and the Plan, which is incorporated herein by reference as a part of this Agreement. In the event of any inconsistency between the Plan and this Agreement, the terms of the Plan shall control. To the extent earned, each Performance Unit represents the right to receive one Common Unit, subject to the terms and conditions set forth in the Grant Notice, this Agreement and the Plan. Unless and until the Performance Units have become earned in the manner set forth in the Grant Notice and this Agreement, Employee will have no right to receive any Common Units or other payments in respect of the Performance Units. Prior to settlement of this Award, the Performance Units and this Award represent an unsecured obligation of Black Stone Minerals, L.P., a Delaware limited partnership (the "Partnership"), payable only from the general assets of the Partnership.

2. **Earning of Performance Units**.

(a) Following the end of the Performance Period, the Committee will determine the level of achievement of the Performance Goals for the Performance Period. The number of Performance Units, if any, that actually become earned for the Performance Period will be determined by the Committee in accordance with the Grant Notice (and any Performance Units that do not become so earned shall be automatically forfeited). Unless and until the Performance Units have become earned and been settled in accordance with Section 3, Employee will have no right to receive any distributions with respect to the Performance Units. In the event of the termination of Employee's employment prior to the last day of the Performance Period, except as otherwise provided in Sections 2(b) and 2(c) below, all of the Performance Units (and all rights arising from such Performance Units and from being a holder thereof), will terminate automatically without any further action by the General Partner or the Partnership and will be automatically forfeited without further notice.

(b) In the event of a Qualifying Termination (as defined in Section 2(e)) prior to the end of the Performance Period and prior to a Change of Control or more than 24 months following a Change of Control, then, subject to Employee's compliance with the release requirement described in Section 2(d), notwithstanding anything to the contrary in the Grant Notice, (i) the Performance Period shall end as of the date of such Qualifying Termination; (ii) the definition of "Average Performance Percentage" shall mean the average of (x) the Production Performance Percentage(s) and the Reserve Performance Percentage(s) for each completed Performance Period Year, if any, ending prior to the date of such Qualifying Termination and (y) the Production Performance Percentage and the Reserve Performance Percentage for the Performance Period Year in which such Qualifying Termination occurs (determined based on year-to-date annualized performance as of the date of such Qualifying Termination); and (iii) the number of Performance Units, if any, that actually become earned for the Performance Period as of the date of such Qualifying Termination shall be determined by multiplying Employee's Target Amount Performance Units for the Performance Period by a fraction, the numerator of which is the number of days Employee was employed by the Employer during the Performance Period and the denominator of which is the number of days in the Performance Period.

(c) If a Qualifying Termination occurs within 24 months following a Change of Control or in the event of a termination of Employee's employment due to Employee's Disability or death prior to the end of the Performance Period, then, subject to Employee's compliance with the release requirement described in Section 2(d), notwithstanding anything to the contrary in the Grant Notice, the number of Performance Units, if any, that actually become earned for the Performance Period will be determined by the Committee in accordance with the Grant Notice assuming that (i) the Performance Period ended as of the date of such termination of employment; and (ii) the definition of "Average Performance Percentage" means the average of (x) the Production Performance Percentage(s) and the Reserve Performance Percentage(s) for each completed Performance Period Year, if any, ending prior to the date of such termination of employment, (y) the Production Performance Percentage and the Reserve Performance Percentage for the Performance Period Year in which such termination of employment occurs (determined based on year-to-date annualized performance as of the date of such termination of employment), and (z) the Production Performance Percentage(s) and the Reserve Performance Percentage(s) for the remaining Performance Period Year(s), if any, assuming the Production Performance Percentage and the Reserve Performance Percentage are each 100% for each such Performance Period Year.

(d) As a condition to the application of the provisions of Section 2(b) or Section 2(c) (other than in the event of a termination of Employee's employment due to Employee's death), Employee must first execute within the time provided to do so (and not revoke in any time provided to do so), a release, in a form acceptable to the General Partner, releasing the Committee, the Employer, the Partnership, the General Partner, their respective Affiliates, and each of the foregoing entities' respective shareholders, members, partners, officers, managers, directors, fiduciaries, employees, representatives, agents and benefit plans (and fiduciaries of such plans) from any and all claims, including any and all causes of action arising out of Employee's employment with the Employer and any of its Affiliates or the termination of such employment, but excluding all claims to payments under the Plan and this Agreement.

(e) As used herein, the following terms have the meanings set forth below:

(i) "Cause" has the meaning assigned to such term in Employee's severance agreement with the General Partner or one of its Affiliates; *provided*, *however*, that if Employee does not have a severance agreement with the General Partner or one of its Affiliates or if such agreement does not define the term "Cause," then "Cause" means a determination by two-thirds of the Board that Employee:

(1) willfully and continually failed to substantially perform Employee's duties to the Partnership and its Affiliates (other than a failure resulting from Employee's Disability);

(2) willfully engaged in conduct that is demonstrably and materially injurious to the Partnership, the General Partner or any of their respective Affiliates, monetarily or otherwise;

(3) has been convicted of, or has plead guilty or *nolo contendere* to, a misdemeanor involving moral turpitude or a felony;

(4) has committed an act of fraud, or material embezzlement or material theft, in each case, in the course of Employee's employment relationship with the Employer or one of its Affiliates, or

(5) has materially breached any obligations of Employee under any written agreement (including any non-compete, non-solicitation or confidentiality covenants) entered into between Employee and 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, Employee shall have 30 days following the delivery of written notice by the Employer or one of its Affiliates within which to cure any actions or omissions described in clauses (1), (2), (4) or (5) constituting Cause; *provided however*, that, if the Employer reasonably expects irreparable injury from a delay of 30 days, the Employer or one of its Affiliates may give Employee notice of such shorter period within which to cure as is reasonable under the circumstances, which may include the termination of Employee's employment without notice and with immediate effect.

(ii) "Disability" means Employee's incapacity, due to accident, sickness or another circumstance that renders Employee unable to perform the essential functions of Employee's job function, with reasonable accommodation, for a period of at least 90 consecutive days or 120 days in any 12-month period.

(iii) "Good Reason" has the meaning assigned to such term in Employee's severance agreement with the General Partner or one of its Affiliates; *provided*, *however*, that if Employee does not have a severance agreement with the General Partner or one of its Affiliates or if such agreement does not define the term "Good Reason," then "Good Reason" means the occurrence of any of the following events without Employee's written consent:

(1) a reduction in Employee's total compensation other than a general reduction in compensation that affects all similarly situated employees in substantially the same proportions;

(2) a relocation of Employee's principal place of employment by more than 50 miles from the location of Employee's principal place of employment as of the Date of Grant;

(3) any material breach by the Partnership or the General Partner of any material provision of this Agreement;

(4) a material, adverse change in Employee's title, authority, duties or responsibilities (other than while Employee has a Disability);

(5) a material adverse change in the reporting structure applicable to Employee; or

(6) following a Change of Control, either (x) a failure of the General Partner or one of its Affiliates to continue in effect any benefit plan or

compensation arrangement in which Employee was participating immediately prior to such Change of Control or (y) the taking of any action by the General Partner or one of its Affiliates that adversely affects Employee's participation in, or materially reduces Employee's benefits or compensation under, any such benefit plan or compensation arrangement, unless, in the case of either clause (x) or (y), 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 Employee's participation is being adversely affected or Employee's benefits or compensation are being materially reduced.

Notwithstanding the foregoing provisions of this definition or any other provision of the Agreement to the contrary, any assertion by Employee of a termination for Good Reason shall not be effective unless all of the following conditions are satisfied: (A) Employee must provide written notice to the General Partner of the existence of the condition(s) providing grounds for termination for Good Reason within 30 days of the initial existence of such grounds; (B) the condition(s) specified in such notice must remain uncorrected for 30 days following the General Partner's receipt of such written notice; and (C) the date of Employee's termination of employment must occur within 60 days after the initial existence of the condition(s) specified in such notice.

(iv) "Qualifying Termination" means a termination of Employee's employment (1) by the Employer without Cause or (2) as a result of Employee's resignation for Good Reason.

3. **Settlement of Performance Units**. As soon as administratively practicable following the Committee's determination of the level of achievement of the Performance Goals for the Performance Period, but in no event later than March 15 following the end of such Performance Period, Employee (or Employee's permitted transferee, if applicable) shall be issued a number of Common Units equal to the number of Performance Units subject to this Award that become earned based on the level of achievement of the Performance Goals as determined by the Committee in accordance with Section 2. Any fractional Performance Unit that becomes earned hereunder will be rounded down to the next whole Performance Unit if it is less than 0.5 and rounded up to the next whole Performance Unit if it is 0.5 or more. No fractional Common Units, nor the cash value of any fractional Common Units, will be issuable or payable to Employee pursuant to this Agreement. All Common Units issued hereunder shall be delivered either by delivering one or more certificates for such Common Units to Employee or by entering such Common Units in book-entry form, as determined by the Committee in its sole discretion. The value of Common Units shall not bear any interest owing to the passage of time. Neither this Section 3 nor any action taken pursuant to or in accordance with this Agreement shall be construed to create a trust or a funded or secured obligation of any kind.

4. **DERs**. Each Performance Unit subject to this Award is hereby granted in tandem with a corresponding DER. Each DER granted hereunder shall remain outstanding from the Date of Grant until the earlier of the settlement or forfeiture of the Performance Unit to which it corresponds (the "DER Period"). If a Common Unit is issued pursuant to Section 3 in settlement of a Performance Unit that becomes earned, then, as soon as administratively practicable following the issuance of such Common Unit, but in no event later than 60 days after the date such Performance Unit becomes earned, the General Partner shall issue to Employee, with respect to the DER corresponding to the earned Performance Unit settled by the issuance of such Common Unit, additional Common Units with a value at the time of issuance equal to the aggregate amount of cash distributions that would have been paid to Employee if Employee were

the record owner of the Common Unit issued to Employee in settlement of Employee's Performance Units as of the applicable record date for each cash distribution paid by the Partnership during the DER Period applicable to such Performance Unit. DERs shall not entitle Employee to any payments relating to distributions paid after the earlier to occur of the applicable Performance Unit settlement date or the forfeiture of the Performance Unit underlying such DER.

5. **Rights as Unitholder**. Neither Employee nor any person claiming under or through Employee shall have any of the rights or privileges of a holder of Common Units in respect of any Common Units that may become deliverable hereunder unless and until certificates representing such Common Units have been issued or recorded in book entry form on the records of the Partnership or its transfer agents or registrars, and delivered in certificate or book entry form to Employee or any person claiming under or through Employee.

6. **Tax Withholding**. Upon any taxable event arising in connection with the Performance Units or the DERs, the General Partner shall have the authority and the right to deduct or withhold (or cause the Employer or one of its Affiliates to deduct or withhold), or to require Employee to remit to the General Partner (or the Employer or one of its Affiliates), an amount sufficient to satisfy all applicable federal, state and local taxes required by law to be withheld with respect to such event. In satisfaction of the foregoing requirement, unless otherwise determined by the Committee, the General Partner or the Employer or one of its Affiliates shall withhold from any cash or equity remuneration (including, if applicable, any of the Common Units otherwise deliverable under this Agreement) then or thereafter payable to Employee an amount equal to the aggregate amount of taxes required to be withheld with respect to such event. If such tax obligations are satisfied through the withholding or surrender of Common Units pursuant to this Agreement, the maximum number of Common Units that may be so withheld (or surrendered) shall be the number of Common Units that have an aggregate Fair Market Value on the date of withholding (or surrender) equal to the aggregate amount of taxes required to be withheld, determined based on the greatest withholding rates for federal, state, local and foreign income tax and payroll tax purposes that may be utilized without resulting in adverse accounting, tax or other consequences to the General Partner or any of its Affiliates (other than immaterial administrative, reporting or similar consequences), as determined by the Committee. Employee acknowledges and agrees that none of the Board, the Committee, the General Partner, the Partnership, the Employer or any of their respective Affiliates have made any representation or warranty as to the tax consequences to Employee as a result of the receipt of the Performance Units and the DERs, the earning of the Performance Units and the DERs or the forfeiture of any of the Performance Units and the DERs. Employee represents that he is in no manner relying on the Board, the Committee, the General Partner, the Partnership, the Employer or any of their respective Affiliates or any of their respective managers, directors, officers, employees or authorized representatives (including, without limitation, attorneys, accountants, consultants, bankers, lenders, prospective lenders and financial representatives) for tax advice or an assessment of such tax consequences. Employee represents that he has consulted with any tax consultants that Employee deems advisable in connection with the Performance Units and the DERs.

7. **Refusal to Transfer; Stop-Transfer Notices**. The Partnership shall not be required (a) to transfer on its books any Common Units that have been sold or otherwise transferred in violation of any of the provisions of this Agreement or (b) to treat as owner of such Common Units or to accord the right to vote or pay distributions to any purchaser or other transferee to whom such Common Units shall have been so transferred. Employee agrees that, in order to ensure compliance with the restrictions referred to herein, the Partnership or the General Partner may issue appropriate "stop transfer" instructions to its transfer agent, if any, and that, if

the Partnership transfers its own securities, it may make appropriate notations to the same effect in its own records.

8. **Non-Transferability**. None of the Performance Units, the DERs or any interest or right therein shall be (a) sold, pledged, assigned or transferred in any manner during the lifetime of Employee other than by will or the laws of descent and distribution, unless and until the Common Units underlying the Performance Units have been issued, and all restrictions applicable to such Common Units have lapsed, or (b) liable for the debts, contracts or engagements of Employee or his or her successors in interest. Except to the extent expressly permitted by the preceding sentence, any purported sale, pledge, assignment, transfer, attachment or encumbrance of the Performance Units, the DERs or any interest or right therein shall be null, void and unenforceable against the Partnership, the General Partner, the Employer and their respective Affiliates.

9. **Compliance with Securities Law**. Notwithstanding any provision of this Agreement to the contrary, the issuance of Common Units hereunder will be subject to compliance with all applicable requirements of applicable law with respect to such securities and with the requirements of any securities exchange or market system upon which the Common Units may then be listed. No Common Units will be issued hereunder if such issuance would constitute a violation of any applicable law or regulation or the requirements of any securities exchange or market system upon which the Common Units may then be listed. In addition, Common Units will not be issued hereunder unless (a) a registration statement under the Securities Act of 1933, as amended (the "Securities Act") is in effect at the time of such issuance with respect to the Common Units to be issued or (b) in the opinion of legal counsel to the Partnership, the Common Units to be issued are permitted to be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Partnership to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Partnership's legal counsel to be necessary for the lawful issuance and sale of any Common Units hereunder will relieve the Partnership of any liability in respect of the failure to issue such Common Units as to which such requisite authority has not been obtained. As a condition to any issuance of Common Units hereunder, the General Partner or the Partnership may require Employee to satisfy any requirements that may be necessary or appropriate to evidence compliance with any applicable law or regulation and to make any representation or warranty with respect to such compliance as may be requested by the General Partner or the Partnership.

10. **No Right to Continued Employment or Awards**.

(a) For purposes of this Agreement, Employee shall be considered to be employed by the Employer as long as Employee remains an "Employee" (as such term is defined in the Plan), or an employee of a corporation or other entity (or a parent or subsidiary of such corporation or other entity) assuming or substituting a new award for this Award. Without limiting the scope of the preceding sentence, it is specifically provided that Employee shall be considered to have terminated employment at the time of the termination of the status of the entity or other organization that employs Employee as an "Affiliate" of the General Partner. Nothing in the adoption of the Plan, nor the award of the Performance Units or DERs thereunder pursuant to the Grant Notice and this Agreement, shall confer upon Employee the right to continued employment by, or a continued service relationship with, the Employer or any of its Affiliates, or any other entity, or affect in any way the right of the Employer or any such Affiliate, or any other entity to terminate such employment at any time. Unless otherwise provided in a written employment agreement or by applicable law, Employee's employment by the Employer, or any such Affiliate, or any other entity shall be on an at-will basis, and the employment relationship may be terminated at any time by either Employee or the Employer, or any such Affiliate, or other entity for any reason whatsoever, with or without cause or notice. Any question as to whether and when there has been a termination of such employment, and the cause of such termination, shall be determined by the Committee or its delegate, and such determination shall be final, conclusive and binding for all purposes.

(b) The grant of the Performance Units and DERs is a one-time Award and does not create any contractual or other right to receive a grant of Awards or benefits in lieu of Awards in the future. Future Awards will be at the sole discretion of the Committee.

11. **Notices**. Any notices or other communications provided for in this Agreement shall be sufficient if in writing. In the case of Employee, such notices or communications shall be effectively delivered if hand delivered to Employee at Employee's principal place of employment or if sent by registered or certified mail to Employee at the last address Employee has filed with the Employer. In the case of the Partnership or General Partner, such notices or communications shall be effectively delivered if sent by registered or certified mail to the General Partner at its principal executive offices.

12. **Agreement to Furnish Information**. Employee agrees to furnish to the General Partner all information requested by the General Partner to enable the General Partner or any of its Affiliates to comply with any reporting or other requirement imposed upon the General Partner or any of its Affiliates by or under any applicable statute or regulation.

13. **Entire Agreement; Amendment**. 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 Performance Units and DERs granted hereunder; *provided, however*, that the terms of this Agreement shall not modify and shall be subject to the terms and conditions of any employment and/or severance agreement between the Partnership, the General Partner, the Employer or any of their respective Affiliates and Employee in effect as of the date a determination is to be made under this Agreement. Without limiting the scope of the preceding sentence, except as provided therein, all prior understandings and agreements, if any, among the parties hereto relating to the subject matter hereof are hereby null and void and of no further force and effect. The Committee may, in its sole discretion, amend this Agreement from time to time in any manner that is not inconsistent with the Plan; *provided, however,* that except as otherwise provided in the Plan or this Agreement, any such amendment that materially reduces the rights of Employee shall be effective only if it is in writing and signed by both Employee and an authorized officer of the General Partner.

14. **Governing Law**. This Agreement shall be governed by, and construed in accordance with, the laws of the State of Delaware, without regard to conflicts of law principles thereof.

15. **Successors and Assigns**. The General Partner may assign any of its rights under this Agreement without Employee's consent. This Agreement will be binding upon and inure to the benefit of the successors and assigns of the General Partner. Subject to the restrictions on transfer set forth herein and in the Plan, this Agreement will be binding upon Employee and Employee's beneficiaries, executors, administrators and the person(s) to whom the Performance Units or DERs may be transferred by will or the laws of descent or distribution.

16. **Clawback**. Notwithstanding any provision in this Agreement or the Grant Notice to the contrary, to the extent required by (a) applicable law, including, without limitation, the

requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, any Securities and Exchange Commission rule or any applicable securities exchange listing standards and/or (b) any policy that may be adopted or amended by the Board from time to time, all Common Units issued hereunder shall be subject to forfeiture, repurchase, recoupment and/or cancellation to the extent necessary to comply with such law(s) and/or policy.

17. **Severability**. If a court of competent jurisdiction determines that any provision of this Agreement is invalid or unenforceable, then the invalidity or unenforceability of such provision 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.

18. **Code Section 409A**. None of the Performance Units, DERs or any amounts payable pursuant to this Agreement are intended to constitute or provide for a deferral of compensation that is subject to Section 409A of the Code and the Treasury regulations and other interpretive guidance issued thereunder (collectively, "Section 409A"). Nevertheless, to the extent that the Committee determines that the Performance Units or DERs may not be exempt from Section 409A, then, if Employee is deemed to be a "specified employee" within the meaning of Section 409A, as determined by the Committee, at a time when Employee becomes eligible for settlement of the Performance Units or DERs upon his "separation from service" within the meaning of Section 409A, then to the extent necessary to prevent any accelerated or additional tax under Section 409A, such settlement will be delayed until the earlier of: (a) the date that is six months following Employee's separation from service and (b) Employee's death. Notwithstanding the foregoing, none of the Partnership, the General Partner, the Employer or any of their respective Affiliates makes any representations that the payments provided under this Agreement are exempt from or compliant with Section 409A and in no event shall the Partnership, the General Partner, the Employer or any of their respective Affiliates be liable for all or any portion of any taxes, penalties, interest or other expenses that may be incurred by Employee on account of non-compliance with Section 409A.

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BLACK STONE MINERALS, L.P.
LONG-TERM INCENTIVE PLAN

RESTRICTED UNIT AWARD GRANT NOTICE

Pursuant to the terms and conditions of the Black Stone Minerals, L.P. Long-Term Incentive Plan, as amended from time to time (the "Plan"), Black Stone Minerals GP, L.L.C., a Delaware limited liability company (the "General Partner"), hereby grants to the individual listed below ("you" or "Employee") the number of Restricted Units (all of which shall consist of Common Units) set forth below (the "Restricted Units"). This award of Restricted Units (this "Award") is subject to the terms and conditions set forth herein as well as the terms and conditions set forth in the Restricted Unit Award Agreement attached hereto as Exhibit A (the "Agreement") and in the Plan, each of which is incorporated herein by reference. Capitalized terms used but not defined herein shall have the meanings set forth in the Plan.

Employee:	[[FIRSTNAME]] [[MIDDLENAME]] [[LASTNAME]]
Date of Grant:	[[GRANTDATE]]
Employer:	Black Stone Natural Resources Management Company or any other entity that may employ Employee after the Date of Grant and which entity is the General Partner, Black Stone Minerals, L.P., a Delaware limited partnership (the "Partnership"), or any of their respective Affiliates.
Number of Restricted Units Granted:	[[SHARESGRANTED]] Restricted Units
Vesting Schedule:	Subject to the Agreement, the Plan and the other terms and conditions set forth herein, the Restricted Units (rounded to the nearest whole number of Restricted Units, except in the case of the final vesting date) shall vest in accordance with the following schedule so long as you remain continuously employed by the Employer from the Date of Grant through each vesting date set forth below:

Vesting Date	**Portion of the Award that Becomes Vested**
[●]	1/3
[●]	1/3
[●]	1/3

By clicking to accept, you agree to be bound by the terms and conditions of the Plan, the Agreement and this Restricted Unit Award Grant Notice (this "Grant Notice"). You acknowledge that you have reviewed the Agreement, the Plan and this Grant Notice in their entirety and fully understand all provisions of the Agreement, the Plan and this Grant Notice. You hereby agree to accept as binding, conclusive and final all decisions or interpretations of the Committee regarding any questions or determinations arising under the Agreement, the Plan or this Grant Notice.

In lieu of receiving documents in paper format, you agree, to the fullest extent permitted by applicable law, to accept electronic delivery of any documents that the General Partner or any Affiliate may be required to deliver (including prospectuses, prospectus supplements, grant or award notifications and agreements, account statements, annual and quarterly reports, and all other forms of communications) in connection with this and any other award made or offered by the General Partner. Electronic delivery may be made via the electronic mail system of the General Partner or one of its Affiliates or by reference to a location on an intranet site to which you have access. You hereby consent to any and all procedures the General Partner has established or may establish for an electronic signature system for delivery and acceptance of any such documents.

You also understand and acknowledge that you should consult with your tax advisor regarding the advisability of filing with the Internal Revenue Service an election under Section 83(b) of the Internal Revenue Code (a "Section 83(b) Election") with respect to the Restricted Units. This election must be filed no later than 30 days after Date of Grant. This time period cannot be extended. If you wish to file a Section 83(b) Election, an election form is attached to this Grant Notice as Exhibit B. By clicking to accept, you acknowledge that (a) you have been advised to consult with a tax advisor regarding the tax consequences of the Restricted Units and (b) the timely filing of a Section 83(b) Election is your sole responsibility, even if you request the Employer, the General Partner or any of their respective Affiliates or any of their respective managers, directors, officers, employees or authorized representatives (including attorneys, accountants, consultants, bankers, lenders, prospective lenders and financial representatives) to assist in making such filing or to file such election on your behalf.

You acknowledge and agree that clicking to accept this Award constitutes your electronic signature and is intended to have the same force and effect as your manual signature.

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Signature Page Follows

IN WITNESS WHEREOF, the General Partner has caused this Grant Notice to be executed by an officer thereunto duly authorized effective for all purposes as provided above.

BLACK STONE MINERALS GP, L.L.C.

By: ________________________________
Steve Putman
Senior Vice President, General Counsel
and Secretary

EXHIBIT A

RESTRICTED UNIT AWARD AGREEMENT

This Restricted Unit Award Agreement (this "Agreement") is made as of the Date of Grant set forth in the Grant Notice to which this Agreement is attached (the "Date of Grant") by and between Black Stone Minerals GP, L.L.C., a Delaware limited liability company (the "General Partner"), and [[FIRSTNAME]] [[MIDDLENAME]] [[LASTNAME]] ("Employee"). Capitalized terms used but not specifically defined herein shall have the meanings specified in the Plan or the Grant Notice.

1. **Award**. Effective as of the Date of Grant, the General Partner hereby grants to Employee the number of Restricted Units (all of which shall consist of Common Units) set forth in the Grant Notice (the "Restricted Units") on the terms and conditions set forth in the Grant Notice, this Agreement and the Plan, which is incorporated herein by reference as a part of this Agreement. In the event of any inconsistency between the Plan and this Agreement, the terms of the Plan shall control.

2. **Issuance Mechanics**. The General Partner shall (a) cause a certificate or certificates representing such Common Units to be registered in the name of Employee, or (b) cause such Common Units to be held in book-entry form. If a certificate is issued, it shall be delivered to and held in custody by the General Partner and shall bear such legend or legends as the Committee deems appropriate in order to reflect the Forfeiture Restrictions (as defined below) and to ensure compliance with the terms and provisions of this Agreement, the rules, regulations and other requirements of the United States Securities and Exchange Commission, any applicable federal or state securities laws or any securities exchange on which the Common Units are then listed or quoted. If the Common Units are held in book-entry form, then such entry will reflect that the Common Units are subject to the restrictions of this Agreement.

3. **Forfeiture Restrictions**.

(a) The Restricted Units may not be sold, assigned, pledged, exchanged, hypothecated or otherwise transferred, encumbered or disposed of except as provided in this Agreement or the Plan. In the event of the termination of Employee's employment with the Employer, except as otherwise expressly provided in this Agreement, Employee shall immediately and without any further action by the General Partner, forfeit and surrender for no consideration all of the Restricted Units with respect to which the Forfeiture Restrictions have not lapsed as of the date of such termination. The prohibition against transfer and the obligation to forfeit and surrender the Restricted Units upon termination of Employee's employment as provided in this Section 3(a) are referred to herein as the "Forfeiture Restrictions." The Forfeiture Restrictions shall be binding upon and enforceable against any transferee of the Restricted Units.

(b) In the event of a Qualifying Termination (as defined in Section 3(d)) prior to the vesting of all of the Restricted Units, subject to Employee's compliance with the release requirement described in Section 3(f), the Forfeiture Restrictions on the Applicable Restricted Units (as defined in Section 3(d)) shall automatically lapse and the Applicable Restricted Units shall immediately thereafter become Earned Units so long as Employee has remained continuously employed by the Employer from the Date of Grant through the date of such Qualifying Termination; provided, however, that if such Qualifying Termination occurs within 24 months following a Change of Control, the Forfeiture Restrictions on all unvested Restricted Units will lapse automatically in accordance with Section 3(e) without any further action by the

General Partner or the Partnership and such Restricted Units shall immediately thereafter become Earned Units so long as Employee has remained continuously employed by the Employer from the Date of Grant through the date of such Qualifying Termination.

(c) In the event of a termination of Employee's employment due to Employee's Disability (as defined in Section 3(d)) or death prior to the vesting of all of the Restricted Units, the Forfeiture Restrictions on all unvested Restricted Units will lapse automatically in accordance with Section 3(e) without any further action by the General Partner or the Partnership and such Restricted Units shall immediately thereafter become Earned Units so long as Employee has remained continuously employed by the Employer from the Date of Grant through the date of such termination.

(d) As used herein, the following terms have the meanings set forth below:

(i) "<u>Applicable Restricted Units</u>" means the number of Restricted Units equal to A *minus* B, where "A" is the product of (x) the number of Restricted Units granted hereunder and (y) a fraction, the numerator of which is the number of days during the period beginning on the Date of Grant and ending on the date of Employee's Qualifying Termination, and the denominator of which is the number of days during the period beginning on the Date of Grant and ending on the last vesting date set forth in the Grant Notice; and "B" is the cumulative number of Restricted Units that became vested prior to the date of Employee's Qualifying Termination.

(ii) "<u>Cause</u>" has the meaning assigned to such term in Employee's severance agreement with the General Partner or one of its Affiliates; *provided*, *however*, that if Employee does not have a severance agreement with the General Partner or one of its Affiliates or if such agreement does not define the term "Cause," then "Cause" means a determination by two-thirds of the Board that Employee:

(1) willfully and continually failed to substantially perform Employee's duties to the Partnership and its Affiliates (other than a failure resulting from Employee's Disability);

(2) willfully engaged in conduct that is demonstrably and materially injurious to the Partnership, the General Partner or any of their respective Affiliates, monetarily or otherwise;

(3) has been convicted of, or has plead guilty or *nolo contendere* to, a misdemeanor involving moral turpitude or a felony;

(4) has committed an act of fraud, or material embezzlement or material theft, in each case, in the course of Employee's employment relationship with the Employer or one of its Affiliates, or

(5) has materially breached any obligations of Employee under any written agreement (including any non-compete, non-solicitation or confidentiality covenants) entered into between Employee and 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, Employee shall have 30 days following the delivery of written notice by the Employer or one of its Affiliates within which to cure any actions or omissions described in clauses (1), (2), (4) or (5) constituting Cause; *provided however*, that, if the Employer reasonably expects irreparable injury from a delay of 30 days, the Employer or one of its Affiliates may give Employee notice of such shorter period within which to cure as is reasonable under the circumstances, which may include the termination of Employee's employment without notice and with immediate effect.

(iii) "Disability" means Employee's incapacity, due to accident, sickness or another circumstance, that renders Employee unable to perform the essential functions of Employee's job function, with reasonable accommodation, for a period of at least 90 consecutive days or 120 days in any 12-month period.

(iv) "Good Reason" has the meaning assigned to such term in Employee's severance agreement with the General Partner or one of its Affiliates; *provided*, *however*, that if Employee does not have a severance agreement with the General Partner or one of its Affiliates or if such agreement does not define the term "Good Reason," then "Good Reason" means the occurrence of any of the following events without Employee's written consent:

(1) a reduction in Employee's total compensation other than a general reduction in compensation that affects all similarly situated employees in substantially the same proportions;

(2) a relocation of Employee's principal place of employment by more than 50 miles from the location of Employee's principal place of employment as of the Date of Grant;

(3) any material breach by the Partnership or the General Partner of any material provision of this Agreement;

(4) a material, adverse change in Employee's title, authority, duties or responsibilities (other than while Employee has a Disability);

(5) a material adverse change in the reporting structure applicable to Employee; or

(6) following a Change of Control, either (x) a failure of the General Partner or one of its Affiliates to continue in effect any benefit plan or compensation arrangement in which Employee was participating immediately prior to such Change of Control or (y) the taking of any action by the General Partner or one of its Affiliates that adversely affects Employee's participation in, or materially reduces Employee's benefits or compensation under, any such benefit plan or compensation arrangement, unless, in the case of either clause (x) or (y), 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 Employee's participation is being adversely affected or Employee's benefits or compensation are being materially reduced.

Notwithstanding the foregoing provisions of this definition or any other provision of the Agreement to the contrary, any assertion by Employee of a termination for Good Reason shall not be effective unless all of the following conditions are satisfied: (A) Employee must provide written notice to the General Partner of the existence of the condition(s) providing grounds for termination for Good Reason within 30 days of the initial existence of such grounds; (B) the condition(s) specified in such notice must remain uncorrected for 30 days following the General Partner's receipt of such written notice; and (C) the date of Employee's termination of employment must occur within 60 days after the initial existence of the condition(s) specified in such notice.

(v) "Qualifying Termination" means a termination of Employee's employment by reason of (1) a termination of Employee's employment by the Employer without Cause, or (2) Employee's resignation for Good Reason.

(e) The Restricted Units shall be released from the Forfeiture Restrictions in accordance with the vesting schedule set forth in the Grant Notice. The Restricted Units with respect to which the Forfeiture Restrictions lapse without forfeiture are referred to herein as the "Earned Units." As soon as administratively practicable following the release of any Restricted Units from the Forfeiture Restrictions, the General Partner shall, as applicable, either deliver to Employee the certificate or certificates representing such Common Units in the General Partner's possession belonging to Employee, or, if the Common Units are held in book-entry form, then the General Partner shall remove the notations indicating that the Common Units are subject to the restrictions of this Agreement. Employee (or the beneficiary or personal representative of Employee in the event of Employee's death or disability, as the case may be) shall deliver to the General Partner any representations or other documents or assurances as the General Partner or its representatives deem necessary or advisable in connection with any such delivery.

(f) As a condition to any accelerated vesting described herein, Employee must first execute within the time provided to do so (and not revoke in any time provided to do so), a release, in a form acceptable to the General Partner, releasing the Committee, the Employer, the Partnership, the General Partner, their respective Affiliates, and each of the foregoing entities' respective shareholders, members, partners, officers, managers, directors, fiduciaries, employees, representatives, agents and benefit plans (and fiduciaries of such plans) from any and all claims, including any and all causes of action arising out of Employee's employment with the Employer and any of its Affiliates or the termination of such employment, but excluding all claims to payments under the Plan and this Agreement.

4. **Distributions**. Distributions that are paid or distributed with respect to a Restricted Unit (whether in the form of Units or other property (including cash)) shall be paid and distributed to Employee on or within 30 days following the date distributions are made to the unitholders of the Partnership, regardless of whether the Restricted Units have become vested. Distributions paid or distributed in the form of securities with respect to Restricted Units shall bear such legends, if any, as may be determined by the Committee from time to time to reflect the terms and conditions of this Agreement and to comply with applicable securities laws.

5. **Rights as Unitholder**. Except as otherwise provided herein, upon issuance of the Restricted Units, Employee shall have all the rights of a holder of Common Units with respect to such Restricted Units subject to the restrictions herein, including the right to vote the Common Units.

6. **Tax Withholding**. Upon any taxable event arising in connection with the Restricted Units, the General Partner shall have the authority and the right to deduct or withhold (or cause the Employer or one of its Affiliates to deduct or withhold), or to require Employee to remit to the General Partner (or the Employer or one of its Affiliates), an amount sufficient to satisfy all applicable federal, state and local taxes required by law to be withheld with respect to such event. In satisfaction of the foregoing requirement, unless otherwise determined by the

Committee, the General Partner or the Employer or one of its Affiliates shall withhold, or cause to be surrendered, from any cash or equity remuneration (including any of the Common Units issued under this Agreement) then or thereafter payable to Employee an amount equal to the aggregate amount of taxes required to be withheld with respect to such event. If such tax obligations are satisfied through the withholding or surrender of Common Units pursuant to this Agreement, the number of Common Units so withheld (or surrendered) shall be the number of Common Units that have an aggregate Fair Market Value on the date of withholding equal to the aggregate amount of taxes required to be withheld, determined based on the greatest withholding rates for federal, state, local and foreign income tax and payroll tax purposes, as determined by the Committee. Employee acknowledges and agrees that none of the Board, the Committee, the General Partner, the Partnership, the Employer or any of their respective Affiliates has made any representation or warranty as to the tax consequences to Employee as a result of the receipt of the Restricted Units, the lapse of any Forfeiture Restrictions or the forfeiture of any of the Restricted Units pursuant to the Forfeiture Restrictions. Employee represents that he is in no manner relying on the Board, the Committee, the Partnership, General Partner, the Employer or any of their respective Affiliates or any of their respective managers, directors, officers, employees or authorized representatives (including, without limitation, attorneys, accountants, consultants, bankers, lenders, prospective lenders and financial representatives) for tax advice or an assessment of such tax consequences. Employee represents that he has consulted with any tax consultants that Employee deems advisable in connection with the Restricted Units.

7. **Refusal to Transfer; Stop-Transfer Notices**. The Partnership shall not be required (a) to transfer on its books any Common Units that have been sold or otherwise transferred in violation of any of the provisions of this Agreement or (b) to treat as owner of such Common Units or to accord the right to vote or pay distributions to any purchaser or other transferee to whom such Common Units shall have been so transferred. Employee agrees that, in order to ensure compliance with the restrictions referred to herein, the Partnership or the General Partner may issue appropriate “stop transfer” instructions to its transfer agent, if any, and that, if the Partnership transfers its own securities, it may make appropriate notations to the same effect in its own records.

8. **Restricted Units Not Transferable**. Prior to becoming Earned Units, the Restricted Units may not be (a) sold, pledged, assigned or transferred in any manner during the lifetime of Employee other than by will or the laws of descent and distribution, unless and until the Forfeiture Restrictions have lapsed, or (b) liable for the debts, contracts or engagements of Employee or his or her successors in interest. Except to the extent expressly permitted by the preceding sentence, any purported sale, pledge, assignment, transfer, attachment or encumbrance of the Restricted Units or any interest or right therein shall be null, void and unenforceable against the Partnership, the General Partner, the Employer and their respective Affiliates.

9. **Section 83(b) Election**. If Employee makes an election under Section 83(b) of the Code to be taxed with respect to the Restricted Units as of the Date of Grant rather than as of the date or dates upon which Employee would otherwise be taxable under Section 83(a) of the Code, Employee hereby agrees to (a) use the election form provided in Exhibit B for such purpose and (b) deliver a copy of such election to the General Partner promptly after filing such election with the Internal Revenue Service.

10. **No Right to Continued Employment or Awards**.

(a) For purposes of this Agreement, Employee shall be considered to be employed by the Employer as long as Employee remains an “Employee” (as such term is defined in the Plan), or an employee of a corporation or other entity (or a parent or subsidiary of such corporation or other entity) assuming or substituting a new award for this Award. Without limiting the scope of the preceding sentence, it is specifically provided that Employee shall be considered to have terminated employment at the time of the termination of the status of the entity or other organization that employs Employee as an "Affiliate" of the General Partner. Nothing in the adoption of the Plan, nor the grant of the Restricted Units pursuant to the Grant Notice and this Agreement, shall confer upon Employee the right to continued employment by, or a continued service relationship with, the Employer or any of its Affiliates, or any other entity, or affect in any way the right of the Employer or any such Affiliate, or any other entity to terminate such employment at any time. Unless otherwise provided in a written employment agreement or by applicable law, Employee's employment by the Employer, or any such Affiliate, or any other entity shall be on an at-will basis, and the employment relationship may be terminated at any time by either Employee or the Employer, or any such Affiliate, or other entity for any reason whatsoever, with or without cause or notice. Any question as to whether and when there has been a termination of such employment, and the cause of such termination, shall be determined by the Committee or its delegate, and such determination shall be final, conclusive and binding for all purposes.

(b) The grant of the Restricted Units is a one-time Award and does not create any contractual or other right to receive a grant of Awards or benefits in lieu of Awards in the future. Future Awards will be at the sole discretion of the Committee.

11. **Notices**. Any notices or other communications provided for in this Agreement shall be sufficient if in writing. In the case of Employee, such notices or communications shall be effectively delivered if hand delivered to Employee at Employee's principal place of employment or if sent by registered or certified mail to Employee at the last address Employee has filed with the Employer. In the case of the Partnership or General Partner, such notices or communications shall be effectively delivered if sent by registered or certified mail to the General Partner at its principal executive offices.

12. **Agreement to Furnish Information**. Employee agrees to furnish to the General Partner all information requested by the General Partner to enable the General Partner or any of its Affiliates to comply with any reporting or other requirement imposed upon the General Partner or any of its Affiliates by or under any applicable statute or regulation.

13. **Entire Agreement; Amendment**. 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 Restricted Units granted hereunder; *provided, however*, that the terms of this Agreement shall not modify and shall be subject to the terms and conditions of any employment and/or severance agreement between the Partnership, the General Partner, the Employer or any of their respective Affiliates and Employee in effect as of the date a determination is to be made under this Agreement. Without limiting the scope of the preceding sentence, except as provided therein, all prior understandings and agreements, if any, among the parties hereto relating to the subject matter hereof are hereby null and void and of no further force and effect. The Committee may, in its sole discretion, amend this Agreement from time to time in any manner that is not inconsistent with the Plan; *provided, however*, that except as otherwise provided in the Plan or this Agreement, any such amendment that materially reduces the rights of Employee shall be effective only if it is in writing and signed by both Employee and an authorized officer of the General Partner.

14. **Governing Law**. This Agreement shall be governed by, and construed in accordance with, the laws of the State of Delaware, without regard to conflicts of law principles thereof.

15. **Successors and Assigns**. The General Partner may assign any of its rights under this Agreement without Employee’s consent. This Agreement will be binding upon and inure to the benefit of the successors and assigns of the General Partner. Subject to the restrictions on transfer set forth herein and in the Plan, this Agreement will be binding upon Employee and Employee's beneficiaries, executors, administrators and the person(s) to whom the Restricted Units may be transferred by will or the laws of descent or distribution.

16. **Clawback**. Notwithstanding any provision in this Agreement or the Grant Notice to the contrary, to the extent required by (a) applicable law, including, without limitation, the requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, any Securities and Exchange Commission rule or any applicable securities exchange listing standards and/or (b) any policy that may be adopted or amended by the Board from time to time, all Restricted Units granted hereunder shall be subject to forfeiture, repurchase, recoupment and/or cancellation to the extent necessary to comply with such law(s) and/or policy.

17. **Severability**. If a court of competent jurisdiction determines that any provision of this Agreement is invalid or unenforceable, then the invalidity or unenforceability of such provision 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.

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EXHIBIT B

SECTION 83(b) ELECTION

The undersigned taxpayer hereby elects, pursuant to Section 83(b) of the Internal Revenue Code of 1986, as amended, to include in gross income as compensation for services the excess (if any) of the fair market value of the property described below over the amount paid for such property.

1. The name, taxpayer identification number and address of the undersigned (the "Taxpayer"), and the taxable year for which this election is being made are:

   Taxpayer's Name: ____________________________

   Taxpayer's Social
   Security Number: ______-______-______

   Taxpayer's Address: ____________________________
   ____

   Taxable Year: Calendar Year ______

2. The property that is the subject of this election (the "Property") is ________ common units of Black Stone Minerals, L.P.

3. The Property was transferred to the Taxpayer on ____________________.

4. The Property is subject to the following restrictions: The units are subject to various transfer restrictions and are subject to forfeiture in the event certain service conditions are not satisfied.

5. The fair market value of the Property at the time of transfer (determined without regard to any restriction other than a nonlapse restriction as defined in Section 1.83-3(h) of the Income Tax Regulations) is $__________ per unit x ________ units = $_______________.

6. The amount paid by the Taxpayer for the Property is $__________ per unit x ________ units = $_______________.

7. The amount to include in gross income is $_______________.

The undersigned taxpayer will file this election with the Internal Revenue Service office with which the taxpayer files his or her annual income tax return not later than 30 days after the date of transfer of the Property. A copy of the election also will be furnished to the person for whom the services were performed. Additionally, the undersigned will include a copy of the election with his or her income tax return for the taxable year in which the Property is transferred. The undersigned is the person performing the services in connection with which the Property was transferred.

Dated:____________________________________ ____
Taxpayer's Signature

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 22, 2023, 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, 2022.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2023

Exhibit 23.2

NSAI 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, 2022, and the inclusion of our corresponding report letter, dated January 13, 2023, in the 2022 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 22, 2023

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 22, 2023

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

Exhibit 31.2

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

I, Jeffrey P. Wood, certify that:

1. I have reviewed this report on Form 10-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 22, 2023

/s/ Jeffrey P. Wood
Jeffrey P. Wood
President and 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 Jeff Wood, 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 22, 2023	/s/ Thomas L. Carter, Jr. Thomas L. Carter, Jr. Chief Executive Officer and Chairman Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.
Date: February 22, 2023	/s/ Jeffrey P. Wood Jeffrey P. Wood President and Chief Financial Officer Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

January 13, 2023

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, 2022, 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, 2022, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	**Oil (MBBL)**	**Gas (MMCF)**	**Total**	**Present Worth at 10%**
Proved Developed Producing	19,184.4	232,035.6	2,938,178.8	1,546,740.5
Proved Developed Non-Producing	—	4,493.3	21,336.7	12,167.6
Proved Undeveloped	—	33,056.9	170,294.6	111,733.2
Total Proved	19,184.4	269,585.8	3,129,810.1	1,670,641.3

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

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1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

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 2022. For oil volumes, the average West Texas Intermediate spot price of $94.14 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $6.357 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 $92.01 per barrel of oil and $6.504 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. Richard B. Talley, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 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/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Executive Chairman

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E. 102425
Chief Executive Officer

Date Signed: January 13, 2023

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.

(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

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

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.

(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 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.*

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

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.