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, 2020

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. ☒

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 $1,015,788,702 on June 30, 2020, the last business day of the registrant's most recently completed second fiscal quarter, based on a closing price of $6.50 per unit as reported by the New York Stock Exchange on such date. As of February 19, 2021, 207,266,383 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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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.

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.

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.

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."

- The COVID-19 pandemic and the significant decline in commodity prices in 2020 has adversely affected our business, and the ultimate effect on our financial condition, results of operations, and cash distributions to unitholders will depend on future developments, which are highly uncertain and cannot be predicted;
- 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;
- There are inherent risks to our business related to our ability to identify, fund, complete, and integrate acquisitions, as well as risks related to completed acquisitions including our ability to obtain subsequent financing, satisfactory title to the assets we acquire, and the occurrence of significant changes to the assets we acquire, among others;
- Risks exists 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;
- We may be unable to obtain needed capital or financing for acquisitions and our non-operated working interests;
- Our credit facility has substantial restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions;
- 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 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 scope and duration of the COVID-19 pandemic and actions taken by the governmental authorities and other parties in response to the pandemic;
- the volatility of realized oil and natural gas prices, including the sharp decline in oil prices that occurred in March and April 2020;
- 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;
- our ability to identify, complete, and integrate acquisitions;
- general economic, business, or industry conditions, including slowdowns, domestically and internationally and volatility in the securities, capital, or credit markets;
- competition in the oil and natural gas industry;
- the level of drilling activity by our operators particularly in areas such as the Shelby Trough where we have concentrated acreage positions;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services, or personnel;
- restrictions on the use of water for hydraulic fracturing;
- the availability of pipeline capacity and transportation facilities;
- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- future operating results;
- future cash flows and liquidity, including our ability to generate sufficient cash to pay quarterly distributions;
- exploration and development drilling prospects, inventories, projects, and programs;
- operating hazards faced by our operators;
- the ability of our operators to keep pace with technological advancements; and
- certain factors discussed elsewhere in this Annual Report.

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

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

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

We are one of the largest owners and managers of oil and natural gas mineral interests in the United States ("U.S."). Our principal business is maximizing the value of our existing 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 relatively stable production and reserves over time with minimal operating costs or capital requirements, 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 1.7 million gross acres. These non-cost-bearing interests, which we refer to collectively as our “mineral and royalty interests,” include ownership in over 70,000 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 Spring 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.

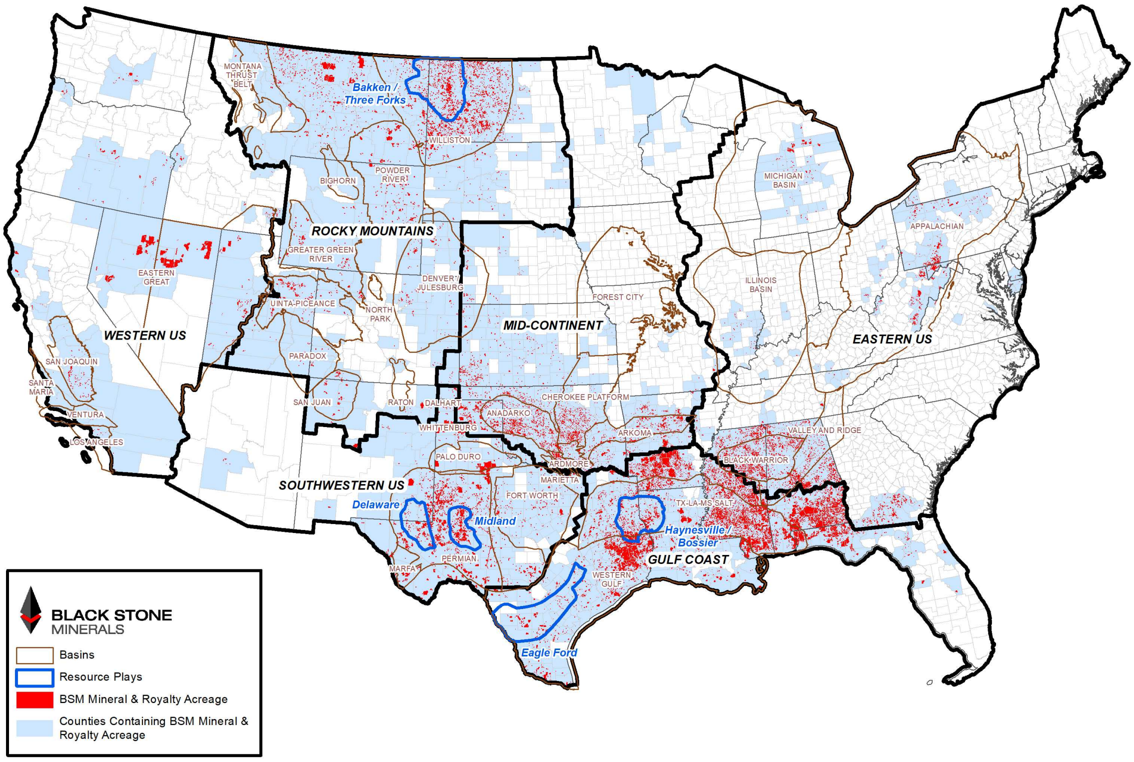
We are a publicly traded Delaware limited partnership formed on September 16, 2014. Our common units trade on the New York Stock Exchange under the symbol "BSM."

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, 2020, our total estimated proved oil and natural gas reserves were 55,987 MBoe based on a reserve report prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), an independent third-party petroleum engineering firm. Of the reserves as of December 31, 2020, approximately 97.1% were proved developed reserves (approximately 93.4% proved developed producing and 3.7% proved developed non-producing) and approximately 2.9% were proved undeveloped reserves. At December 31, 2020, our estimated proved reserves were 28% oil and 72% 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*" based on 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, 2020, 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 East Texas where we own non-operated working interests alongside XTO Energy Inc. ("XTO"), a subsidiary of Exxon Mobil Corporation, and BPX Energy, a subsidiary of BP plc. In 2017, we entered into farmout arrangements (discussed below) for our entire working interest position in that area. We also hold working interests acquired through working interest participation rights, which we often include in the terms of our leases. This participation right complements our core mineral and royalty interest business because it allows us to realize additional value from our minerals. Under the terms of the relevant leases, we are typically granted a unit-by-unit or a well-by-well option to participate on a non-operated working interest basis in drilling opportunities on our mineral acreage. This right to participate in a unit or well is exercisable at our sole discretion. We 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 20% of our total production volumes during the year ended December 31, 2020. As of December 31, 2020, we owned non-operated working interests in 9,718 gross (347 net) wells.

Our 2021 capital expenditure budget associated with our non-operated working interests is expected to be approximately $5 million. The majority of this capital is anticipated to be spent for working interest participation on test wells in the Austin Chalk play and the remaining will be spent for workovers on existing wells in which we own a working interest.

Farmout Agreements

In 2017, we entered into two 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.

Canaan Farmout

In February 2017, we entered into a farmout agreement with Canaan Resource Partners ("Canaan") which covers certain Haynesville and Bossier shale acreage in San Augustine County, Texas operated by XTO. We have an approximate 50% working interest in the acreage and are the largest mineral owner. During the first three phases of the farmout agreement, Canaan commits on a phase-by-phase basis and funds 80% of our drilling and completion costs and is assigned 80% of our working interests in such wells (40% working interest on an 8/8ths basis) as the wells are drilled. After the third phase, Canaan can earn 40% of our working interest (20% working interest on an 8/8ths basis) in additional wells drilled in the area by continuing to fund 40% of our costs for those wells on a well-by-well basis. We receive an overriding royalty interest ("ORRI") before payout and an increased ORRI after payout on all wells drilled under the agreement.

Canaan has participated in a total of 37 wells under the farmout agreement through December 31, 2020 covering two election phases. In 2019, XTO suspended its development activities in the area due to low natural gas prices. Canaan has the right to elect to continue its participation in a third phase covering up to 20 future wells drilled under the farmout agreement should XTO resume drilling activity.

Pivotal Farmout

In November 2017, we entered into a farmout agreement (the "First Pivotal Farmout") with Pivotal Petroleum Partners ("Pivotal"), a portfolio company of Tailwater Capital, LLC. The farmout agreement covers substantially all of our remaining working interests under active development in the Shelby Trough area of East Texas targeting the Haynesville and Bossier shale acreage (after giving effect to the Canaan farmout) until November 2025. Pivotal is obligated to fund the development of up to 80 wells, in designated well groups, across several development areas and then has options to continue funding our working interest across those areas for the duration of the farmout agreement. 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, 2020, a total of 68 wells have been spud in the contract area subject to the First Pivotal Farmout. Our development agreement with BPX Energy terminated in 2019 with respect to the majority of our acreage covered by the farmout agreement with Pivotal. As such, Pivotal retains minimal rights or obligations related to the farmout for that area that remains subject to the First Pivotal Farmout.

In the second quarter of 2020, we entered into a development agreement with Aethon Energy ("Aethon") to develop certain portions of the area forfeited by BPX Energy in Angelina County, Texas. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to our mineral and leasehold acreage in the contract area. The agreement calls for a minimum of four wells to be drilled in the initial program year which began in the third quarter of 2020, increasing to a minimum of 15 wells per year beginning with the third program year. In November 2020, we entered into a new farmout agreement (the "Second Pivotal Farmout") with Pivotal. The Second Pivotal Farmout supersedes and replaces the First Pivotal Farmout with respect to the area covered by the Aethon development agreement. The Second Pivotal Farmout covers our remaining working interests under active development by Aethon in Angelina County, Texas and continues until November 2028, unless earlier terminated in accordance with the terms of the agreement. Pivotal will earn 100% of our remaining working interest (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells drilled and operated by Aethon in accordance with the development agreement. Pivotal is 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 Second 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, 2020, a total of 2 wells have been spud in the contract area subject to the Second Pivotal Farmout.

From the inception of the farmout agreements through December 31, 2020, we have received $90.2 million and $119.2 million from Canaan and Pivotal, respectively, under the agreements. When such reimbursements are received prior to assigning the wells to Canaan and Pivotal, we record the amounts as increases to Oil and natural gas properties and Other long-term liabilities. When working interests in farmout wells are assigned to Canaan and Pivotal, our Oil and natural gas properties and Other long-term liabilities are reduced by the reimbursed capital costs. As of December 31, 2020 and 2019, $0.1 million and $1.7 million, respectively, were included in the Other long-term liabilities line item of the consolidated balance sheets for reimbursements received associated with farmed-out working interests not yet assigned to Canaan and Pivotal.

As a result of the farmout agreements with Canaan and Pivotal and the development agreement with Aethon, we expect net capital requirements associated with non-operated working interests to be minimal in 2021.

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, 2020[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	7,918,289	52.1 %	552,762	4.2 %	241,572	4.0 %	478,349	91,835
Southwestern US	2,756,298	25.5 %	996,219	3.5 %	206,687	1.7 %	29,547	12,941
Rocky Mountains	2,118,864	15.4 %	243,318	3.4 %	909,920	2.5 %	93,952	16,174
Eastern US	1,659,418	47.4 %	1,727	4.0 %	74,912	1.4 %	13,487	1,346
Mid-Continent	1,284,107	34.5 %	38,931	4.0 %	283,226	3.7 %	39,981	23,730
Western US	1,025,563	89.2 %	334	1.8 %	32,965	2.9 %	—	—
Total	16,762,539	43.5 %	1,833,291	3.7 %	1,749,282	2.8 %	655,316	146,026

[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 20%, 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, 2020[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	2020	2019	2018	2020	2019	2018
Gulf Coast	13,086	2,095	18,878	20,702	16,425	6,491	10,312	11,869
Southwestern US	32,905	1,163	6,388	7,052	5,081	143	180	278
Rocky Mountains	14,731	2,032	4,983	5,463	7,050	680	678	934
Eastern US	2,063	256	907	750	886	17	24	22
Mid-Continent	8,585	4,171	1,986	2,223	2,366	837	897	1,120
Western US	851	1	273	257	270	—	1	—
Total	72,221	9,718	33,415	36,447	32,078	8,168	12,092	14,223

[1] We own both mineral and royalty interests and working interests in 4,186 of the wells shown in each column above.

[2] Refers to mineral and royalty interest wells.

Material Resource Plays

The following listing provides an overview of the resource plays we consider most material to our current and future business. These plays accounted for 73% of our aggregate production for the year ended December 31, 2020.

- ***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 Spring, 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, 2020[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	396,784	17.1 %	38,703	1.3 %	12,737	1.4 %	51,900	7,191
Haynesville/Bossier	403,508	61.7 %	28,516	2.2 %	31,026	6.2 %	277,167	53,413
Permian-Midland	222,077	4.9 %	128,471	1.0 %	110,174	0.4 %	160	4
Permian-Delaware	133,817	9.3 %	36,346	0.6 %	5,243	2.9 %	2,482	1,151
Eagle Ford	67,564	14.3 %	106,264	1.2 %	48,440	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 20%, 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.

Resource Play	Gross Well Count as of December 31, 2020[1]		Mineral and Royalty Interests: Average Daily Production (Boe/d) for the Year Ended December 31,			Working Interests: Average Daily Production (Boe/d) for the Year Ended December 31,		
	MRI Wells[2]	WI Wells	2020	2019	2018	2020	2019	2018
Bakken/ Three Forks	3,900	494	3,694	4,150	5,007	485	541	693
Haynesville/Bossier	1,150	104	14,525	15,091	10,273	5,756	9,364	10,657
Permian-Midland	2,184	2	2,640	2,621	1,792	—	—	1
Permian-Delaware	678	26	2,136	2,932	2,207	39	52	65
Eagle Ford	924	25	1,137	1,631	1,920	9	12	12

[1] We own both mineral and royalty interests and working interests in 831 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, 2020, 2019, and 2018 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 Mr. 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, 2020 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 all of our reserve estimates for 2020. Mr. Gremillion is a petroleum engineer with approximately 11 years of reservoir-engineering experience. Brock Morris, our former Senior Vice President, Engineering and Geology, was primarily responsible for overseeing the preparation of all of our reserve estimates for 2019 and 2018. Mr. Morris is a petroleum engineer and had approximately 34 years of reservoir-engineering and operations experience as of December 31, 2019.

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 of our estimated proved reserves as of December 31, 2020, 2019, and 2018 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 unweighted arithmetic average of the first-day-of-the-month market price for each month within the year the estimates are prepared. For estimates of oil reserves, the average WTI spot oil prices used were $39.54, $55.85, and $65.56 per barrel as of December 31, 2020, 2019, and 2018, 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 $1.99, $2.58, and $3.10 per MMBTU as of December 31, 2020, 2019, and 2018, 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 $36.43 per barrel for oil and $1.60 per Mcf for natural gas as of December 31, 2020, $52.15 per barrel for oil and $2.36 per Mcf for natural gas as of December 31, 2019, and $62.81 per barrel for oil and $2.98 per Mcf for natural gas as of December 31, 2018.

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,		
	2020	2019	2018
		(Unaudited)	
Estimated proved developed:			
Oil (MBbls)	15,952	17,050	17,567
Natural gas (MMcf)	230,411	263,371	278,233
Total (MBoe)	54,354	60,945	63,939
Estimated proved undeveloped:			
Oil (MBbls)	—	—	—
Natural gas (MMcf)	9,800	45,587	35,787
Total (MBoe)	1,633	7,598	5,965
Estimated proved reserves:			
Oil (MBbls)	15,952	17,050	17,567
Natural gas (MMcf)	240,211	308,958	314,020
Total (MBoe)	55,987	68,543	69,904
Percent proved developed	97.1 %	88.9 %	91.5 %

Reserve engineering is and must be recognized as 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, 2020, which is included as an exhibit to this Annual Report.

Estimated Proved Undeveloped Reserves

As of December 31, 2020, our PUDs comprised 9,800 MMcf of natural gas, for a total of 1,633 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, 2020 (in MBoe):

	Estimated Proved Undeveloped Reserves (Unaudited)
As of December 31, 2019	7,598
Acquisitions of reserves	—
Divestiture of reserves	—
Extensions and discoveries	1,135
Revisions of previous estimates	(1,545)
Transfers to estimated proved developed	(5,555)
As of December 31, 2020	1,633

New PUD reserves totaling 1,135 MBoe were added during the year ended December 31, 2020, resulting from development activities in the Haynesville/Bossier play. In 2020 we did not acquire or divest any PUD reserves.

During the year ended December 31, 2020, we had reductions of 1,545 MBoe of PUD reserves, primarily as a result of a reduction of royalty on the wells in order to incentivize the operator to complete and turn the wells to sales. We converted the remaining 5,555 MBoe of PUD reserves to PDP reserves.

During the year ended December 31, 2020, no costs were incurred, net of farmout reimbursements, relating to the development of locations that were classified as PUDs as of December 31, 2019. Additionally, during the year ended December 31, 2020, we incurred minimal costs, net of farmout reimbursements, drilling, completing, and recompleting other wells that were not classified as PUDs as of December 31, 2019. There are no estimated future development costs projected for the development of PUD reserves as of December 31, 2020. All our PUD drilling locations as of December 31, 2020 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, 2020, our PUD reserves consists of 5 wells in various stages of drilling. As of December 31, 2020, approximately 3% 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, 2020, 26% of our production and 52% of our oil and natural gas revenues were related to oil and condensate production and sales, respectively. During the same period, natural gas and NGL sales were 74% of our production and 48% of our oil and natural gas revenues.

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

	Year Ended December 31,		
	2020	2019	2018
Production:			
Oil and condensate (MBbls)	3,895	4,777	4,962
Natural gas (MMcf)[1]	67,945	77,635	71,622
Total (MBoe)	15,219	17,716	16,899
Average daily production (MBoe/d)	41.6	48.5	46.3
Realized Prices without Derivatives:			
Oil and condensate (per Bbl)	$ 38.16	$ 55.20	$ 62.53
Natural gas and natural gas liquids sales (per Mcf)[1]	$ 2.04	$ 2.57	$ 3.47
Unit Cost per Boe:			
Production costs and ad valorem taxes	$ 2.86	$ 3.42	$ 3.81

[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, 2020[1]		
	Mineral and Royalty Interests	Working Interests	
Well Type	Gross	Gross	Net
Oil	50,142	3,687	65
Natural Gas	22,079	6,031	282
Total	72,221	9,718	347

[1] We own both mineral and royalty interests and working interests in 4,186 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, 2020:

BSM Land Region	Developed Acreage[1]	Undeveloped Acreage[1]	Total Acreage[1]
Gulf Coast	1,042,351	7,670,272	8,712,623
Southwestern U.S.	1,245,331	2,713,873	3,959,204
Rocky Mountains	963,570	2,308,532	3,272,102
Eastern U.S.	154,320	1,581,737	1,736,057
Mid-Continent	753,369	852,895	1,606,264
Western U.S.	20,265	1,038,597	1,058,862
Total	4,179,206	16,165,906	20,345,112

[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, 2020:

	Developed Acreage[1]		Undeveloped Acreage[1]		Total Acreage[1]	
BSM Land Region	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	223,195	35,881	255,154	55,954	478,349	91,835
Southwestern U.S.	15,881	11,751	13,666	1,190	29,547	12,941
Rocky Mountains	81,485	14,891	12,467	1,283	93,952	16,174
Eastern U.S.	13,408	1,346	79	—	13,487	1,346
Mid-Continent	38,995	23,711	986	19	39,981	23,730
Western U.S.	—	—	—	—	—	—
Total	372,964	87,580	282,352	58,446	655,316	146,026

[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, 2021, 2022, and 2023, and, where applicable, the net acres expiring that are subject to extension options:

	2021 Expirations		2022 Expirations		2023 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.**
58,446	6,037	963	3,012	1,016	2,802	361

Drilling Results for Our Working Interests

The following table sets forth information with respect to the number of wells 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,		
	2020	**2019**	**2018**
Gross development wells:			
Productive	—	—	6.0
Dry	—	—	—
Total	—	—	6.0
Net development wells:			
Productive	—	—	2.5
Dry	—	—	—
Total	—	—	2.5
Gross exploratory wells:			
Productive	—	1.0	—
Dry	—	—	1
Total	—	1.0	1.0
Net exploratory wells:			
Productive	—	0.3	—
Dry	—	—	1
Total	—	0.3	1.0

As of December 31, 2020, 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 require the acquisition of a permit before drilling commences, restrict the types, quantities, and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive, and other protected areas, require action to prevent, or remediate pollution from current or historic operations, such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses, and authorizations, require that additional pollution controls be installed, and impose substantial liabilities for pollution resulting from operations. 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 the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non- hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development, and production of oil and natural gas are exempt from regulation as hazardous wastes under RCRA, these wastes typically constitute "solid wastes" that are subject to less stringent non-hazardous waste requirements. However, it is possible that RCRA could be amended or the EPA or state environmental agencies could adopt policies to require oil and natural gas exploration, development, and production wastes 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, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons 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. Under CERCLA and comparable state statutes, persons deemed "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. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Oil and natural gas exploration and production activities on our properties use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold our operators, or us as working interest owners if the operator fails to perform, responsible under CERCLA and comparable state statutes for all or part of the costs to clean-up sites at which these "hazardous substances" have been released.

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. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. In June 2015, the EPA and the U.S. Army Corps of Engineers (the “Corps”) published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States ("WOTUS"). Following the change in U.S. Presidential Administrations, there have been several attempts to modify or eliminate this rule. Most recently, on January 23, 2020, the EPA and Corps replaced the WOTUS rule adopted in 2015 with the narrower Navigable Waters Protection Rule, and litigation is expected. Therefore, 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.

In addition, 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 presents an imminent and substantial endangerment to 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 through the issuance of permits and the imposition of other requirements. 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. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard, (“NAAQS”) for ozone from 75 to 70 parts per billion for both the 8- hour primary and secondary standards, and the agency completed attainment/non-attainment designations in July 2018. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit the ability of our operators to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Separately, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. These laws and regulations 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, including one that calls for substantial action on climate change, such as the increased use of zero-emission vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across government agencies and economic sectors. Moreover, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, 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 current administration has also 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.

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. Although the United States had withdrawn from the Paris Agreement, the current administration recently recommitted the United States to the agreement by executive order. However, the impacts of this executive order and the terms of any legislation or regulation to implement the United States' commitment remain unclear at this time.

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. Other actions that could be pursued by the current administration may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emission limitations for oil and gas 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. Additionally, financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. The Federal Reserve recently joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector.

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.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations, or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate the GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for oil and natural gas, which could reduce the profitability of our interests. Additionally, political, litigation, and financial risks may result in our oil and natural gas operators restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing their ability to continue to operate in an economic manner, which also could reduce the profitability of our interests. One or more of these developments could have a material adverse effect on our business, financial condition, or results of operation.

Hydraulic Fracturing

Our operators engage in hydraulic fracturing, 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. 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. For example, the EPA issued effluent limitation guidelines in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. The EPA has not proposed to take any action in response to the report’s findings.

Several states where we own interests in oil and gas producing properties, including Colorado, North Dakota, Louisiana, Oklahoma, 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, both Texas and Oklahoma 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. For example, in April 2019, Colorado adopted legislation that requires the Colorado Oil and Gas Conservation Commission ("COGCC") to prioritize public health and environmental concerns in its decisions and delegates considerable new authority to local governments to regulate surface impacts.

In keeping with this legislation, the COGCC in November 2020 adopted revisions to several regulations to increase protections for public health, safety, welfare, wildlife, and environmental matters. These revisions established more stringent setbacks (2,000 feet instead of 500-feet) on new oil and gas development and elimination of routine flaring and venting of natural gas at new or existing wells across the state, each subject to only limited exceptions. Some local communities have adopted, or are considering adopting, additional restrictions for oil and gas activities, such as requiring greater setbacks. 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. Pursuant to a settlement with environmental groups, the U.S. Fish and Wildlife Service ("USFWS") was required to determine whether over 250 species required listing as threatened or endangered under the ESA. USFWS has not yet completed its review, but the potential remains for new species to be listed under the ESA. 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. For example, recently, there have been renewed calls to review protections currently in place for the Dunes Sagebrush Lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. Likewise, there have been calls to review protections in place for the Greater Sage Grouse, which can be found across a large swath of the northwestern United States in oil and gas producing states. The listing of either of these species, or any others, 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, such loss could impact 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,		
	2020	2019	2018
XTO Energy Inc.	20%	18%	15%

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, 2020, Black Stone Management had 87 full-time employees and 14 contractors. Our largest departments are Accounting and Land Administration, which account for 34 and 18 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 community, 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 18 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.

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.

COVID-19

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

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

The impact of the COVID-19 pandemic has negatively affected the oil and natural gas business environment, primarily by causing a reduction in commercial activity and travel worldwide thereby lowering energy demand. This, in turn, has resulted in significantly lower market prices for oil, natural gas, and NGLs. While we use derivative instruments to partially mitigate the impact of commodity price volatility, our revenues and operating results depend significantly upon the prevailing prices for oil and natural gas. The current price environment has caused many of our operators to reduce their drilling and completion activity on our acreage, and caused some of our operators to temporarily shut-in production from existing wells, both of which negatively impact our production volumes. While we believe most of the shut-in production has been brought back on-line, drilling and completion activity remains depressed relative to pre-pandemic levels.

The current price environment also caused us to determine that certain depletable units consisting of mature oil producing properties were impaired. Therefore, we recognized impairment of oil and natural gas properties of $51.0 million for the year ended December 31, 2020. Additionally, the borrowing base under the Credit Facility, which takes into consideration the estimated loan value of our oil and natural gas properties, was reduced from $650.0 million to $460.0 million, effective May 1, 2020. Effective July 21, 2020, in connection with the closing of our two asset sales in the Permian Basin, the borrowing base was further reduced to $430.0 million. Effective November 3, 2020, the most recent borrowing base redetermination reduced the borrowing base to $400.0 million. In a prolonged period of low commodity prices, we may be required to impair additional properties and the borrowing base under our Credit Facility could be further reduced. In light of the challenging business environment and uncertainty caused by the pandemic, the Board also approved a reduction in the quarterly distribution for the first quarter of 2020 to increase the amount of retained free cash flow for debt reduction and balance sheet protection. The Board approved increases to the quarterly distribution for the second and fourth quarters of 2020, but the distribution remains below 2019 levels.

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

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

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

Cash Distributions

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

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

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

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

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

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

Price of Oil and Natural Gas

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

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

- the domestic and foreign supply of and demand for oil and natural gas;
- market expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing, and delivering oil and natural gas;
- the price and quantity of foreign imports and exports of oil and natural gas;
- political and economic conditions in oil producing regions, including the Middle East, Africa, South America, and Russia;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

- trading in oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- 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, 2020		During the Five Years Prior to 2021		As of December 31,		
	High	Low[3]	High[2]	Low[3]	2020	2019	2018
WTI spot crude oil ($/Bbl)[1]	$ 63.27	$ 8.91	$ 77.41	$ 8.91	$ 48.35	$ 61.14	$ 45.15
Henry Hub spot natural gas ($/MMBtu)[1]	3.14	1.33	6.24	1.33	2.36	2.09	3.25

[1] Source: EIA
[2] High prices for WTI and Henry Hub were in 2018.
[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.

Based on the EIA forecasts for 2021 and 2022, oil prices are expected to trade in a lower range compared to recent historical highs. Approximately 52% of our 2020 oil and natural gas revenues were derived from oil and condensate sales. Any additional 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.

The spot WTI market price at Cushing, Oklahoma has declined from $98.17 per Bbl on December 31, 2013 to $48.35 per Bbl on December 31, 2020. The reduction in price has been caused by many factors, including substantial increases in U.S. oil production from unconventional (shale) reservoirs, with limited increases in demand. 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 and 2016, 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 (defined below) 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. See "—Covid-19— The COVID-19 pandemic and the significant decline in commodity prices in 2020 has adversely affected our business, and the ultimate effect on our financial condition, results of operations, and cash distributions to unitholders will depend on future developments, which are highly uncertain and cannot be predicted.”

Based on the EIA forecasts for 2021 and 2022, natural gas prices are expected to trade in a range lower than historical highs. Approximately 48% of our 2020 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, 2020, natural gas prices at Henry Hub have ranged from a high of $8.15 per MMBtu in 2014 to a low of $1.33 per MMBtu in 2020. On December 31, 2020, the Henry Hub spot market price of natural gas was $2.36 per MMBtu. The reduction in prices has been caused by many factors, including increases in natural gas production from unconventional (shale) reservoirs, without an offsetting increase in demand. The expected increase in natural gas production in 2020, based on reports from the EIA, could cause the prices for natural gas to remain at current levels or fall to lower levels. 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 and 2016, 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. See "—Covid-19— The COVID-19 pandemic and the significant decline in commodity prices in 2020 has adversely affected our business, and the ultimate effect on our financial condition, results of operations, and cash distributions to unitholders will depend on future developments, which are highly uncertain and cannot be predicted.”

Acquisitions

Our failure to successfully identify, complete, and integrate acquisitions could adversely affect our growth, results of operations, and cash distributions to unitholders.

We depend partly on acquisitions to grow our reserves, production, and cash generated from operations. Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data, and other information, the results of which are often inconclusive and subject to various interpretations. The successful acquisition of properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- development plans;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, if applicable, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain financing. In addition, compliance with regulatory requirements may impose substantial additional obligations on our operators, causing them to expend additional time and resources in compliance activities, and potentially increase our operators’ exposure to penalties or fines for non-compliance with additional legal requirements. Further, the process of integrating acquired assets may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources.

No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms, or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully, or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition, results of operations, and cash distributions to unitholders. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our growth, results of operations, and cash distributions to unitholders.

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

Even 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.

<u>Access to Capital and Financing</u>

Acquisitions, funding our non-operated working interests, and our operators' development activities of our leases 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. We have made and may make in the future 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.

In the future, 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.

Most of our operators are also 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.

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, 2020, we had outstanding borrowings of $121.0 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 November 2020 is $400.0 million and the next semi-annual redetermination is scheduled for April 2021. 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.

On July 27, 2017, the U.K. Financial Conduct Authority announced that it intends to stop persuading or compelling banks to submit LIBOR rates after 2021. Our Credit Facility includes provisions to determine a replacement rate for LIBOR if necessary during its term, which require that we and our lenders agree upon a replacement rate based on the then-prevailing market convention for similar agreements. We currently do not expect the transition from LIBOR to have a material impact on us. However, if clear market standards and replacement methodologies have not developed as of the time LIBOR becomes unavailable, we may have difficulty reaching agreement on acceptable replacement rates under our Credit Facility. In the event that we do not reach agreement on an acceptable replacement rate for LIBOR, outstanding borrowings under the Credit Facility would revert to a floating rate equal to the alternative base rate (which, as of the time that LIBOR becomes unavailable, is equal to the greater of the Prime Rate and the Federal Funds effective rate plus 0.50%) plus the applicable margin for the alternative base rate which ranges between 1.00% and 2.00%. If we are unable to negotiate replacement rates on favorable terms, it could have a material adverse effect on our financial condition, results of operations, and cash distributions to unitholders. Please read "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Credit Facility" for a description of the interest rate on outstanding borrowings under our Credit Facility.

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.”

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, 2020, 2019, and 2018 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, 2020, 2019, and 2018 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, 2020, 2019, and 2018, 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, 2020, 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 2020, we generated 13% of our royalty revenues and 54% of our working interest revenues from two operators in the Shelby Trough area of the Haynesville play in East Texas, where we own a concentrated, relatively high-interest royalty position. These operators have recently decided to limit their Shelby Trough drilling activity, and one of the operators has released acreage in the area. 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 drilling activity in this area does not resume at the previous rate, production may decrease, reducing cash generated from operations and, without offsetting cost reductions, 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.

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 which 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. 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. The federal SDWA regulates the underground injection of substances through the Underground Injection Control (“UIC”) program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic-fracturing process is typically regulated by state oil and natural gas commissions. However, the EPA has published effluent limit guidelines prohibiting the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

Additionally, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. The EPA has not proposed to take any action in response to the report’s findings.

Several states where we own interests in oil and natural gas producing properties, including Colorado, North Dakota, Louisiana, Oklahoma, 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, in Texas, the RRC published a final rule in October 2014 governing permitting or re-permitting of disposal wells that require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections, and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the RRC may deny, modify, suspend, or terminate the permit application or existing operating permit for that well. Similarly, Oklahoma has imposed strict limits on the 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. For example, in April 2019, Colorado adopted legislation that requires the COGCC to prioritize public health and environmental concerns in its decisions and delegates considerable new authority to local governments to regulate surface impacts. Some local communities have adopted additional restrictions for oil and gas activities, such as requiring greater setbacks. 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.

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.

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;
- 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, 2020, we had 206,748,889 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, 2020 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 could 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 for publicly traded partnerships. 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.

In past years, 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, to accompany lower U.S. federal income tax rates. 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 the Company’s 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 the new 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 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, subject to the exceptions in the Coronavirus Aid, Relief, and Economic Security Act (the “CARES Act,” discussed below), under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, 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, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion to the extent such depreciation, amortization, or depletion is not capitalized into cost of goods sold with respect to inventory.

For our 2020 taxable year, the CARES Act increases the 30% adjusted taxable income limitation to 50%, unless we elect not to apply such increase. For purposes of determining our 50% adjusted taxable income limitation, we may elect to substitute our 2020 adjusted taxable income with our 2019 adjusted taxable income, which may result in a greater business interest expense deduction.

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.

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, recently issued Treasury regulations provide that the "amount realized" on a transfer of an interest in a publicly traded partnership, such as our 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 publicly traded partnership's liabilities. The Treasury regulations further provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2022, and after that date, if effected through a broker, the obligation to withhold is imposed on the transferor’s broker.

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. In addition, our efforts to monitor, mitigate and manage these evolving risks may result in increased capital and operating costs, but there can be no assurance that such efforts will be sufficient to prevent attacks or breaches from occurring.

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

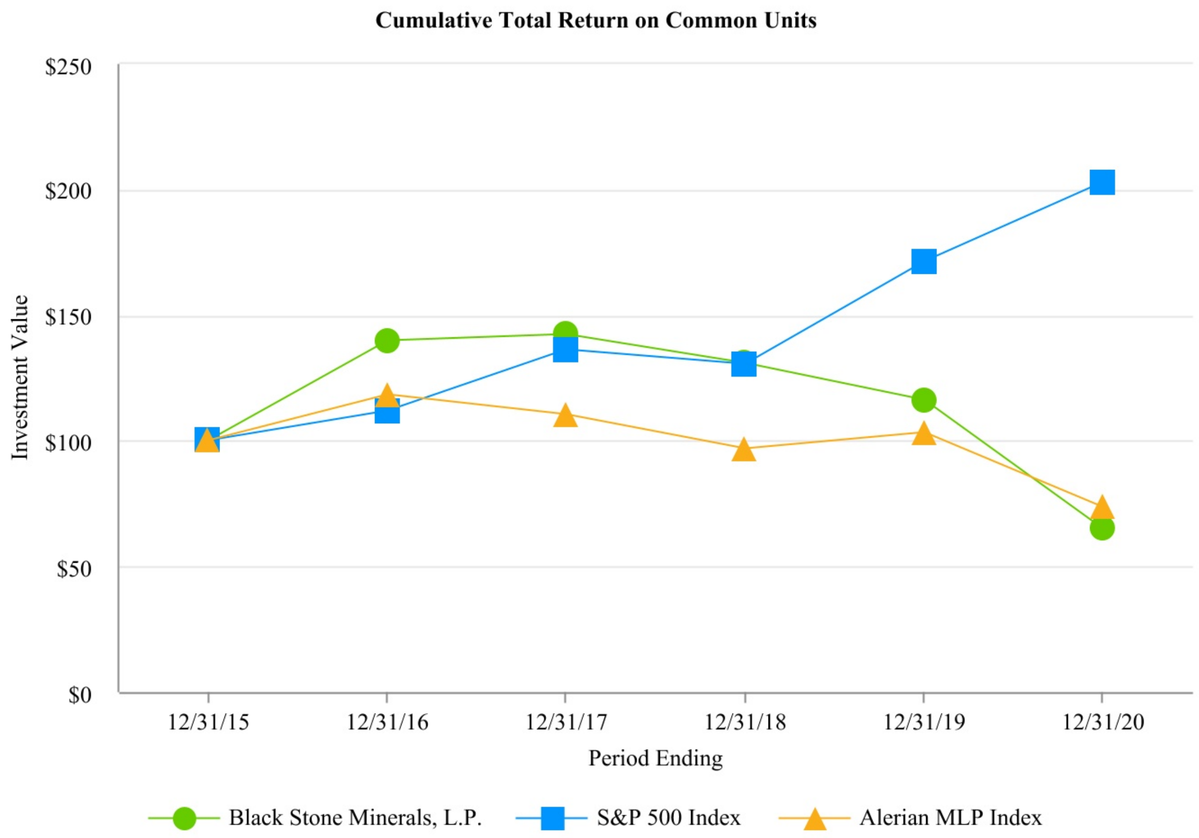
Not applicable.

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 19, 2021, there were 207,266,383 common units outstanding held by 448 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 19, 2021, 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 Alerian MLP index. The graph assumes that the value of the investment in our common units was $100.00 on December 31, 2015. Cumulative return is computed assuming reinvestment of distributions.



Comparison of Cumulative Total Return
Assumes Initial Investment of $100

	As of December 31,					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Black Stone Minerals, L.P.	$ 100.00	$ 139.72	$ 142.29	$ 130.83	$ 116.12	$ 64.97
S&P 500 Index	100.00	111.96	136.40	130.42	171.49	203.04
Alerian MLP Index	100.00	118.31	110.59	96.86	103.21	73.60

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.

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

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.

- Our Credit Facility restricts our distributions if there is a default under our Credit Facility or if our borrowing base is lower than the outstanding loans under our Credit Facility. 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. 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, 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.

Subordinated Units

The limited partners of BSM's Predecessor acquired all of our subordinated units in connection with our IPO. The subordination period under the partnership agreement ended on the first business day after we earned and paid an aggregate amount of at least $1.35 (the annualized minimum quarterly distribution applicable for quarterly periods ending March 31, 2019 and thereafter) multiplied by the total number of outstanding common and subordinated units for a period of four consecutive, non-overlapping quarters ending on or after March 31, 2019, and there were no outstanding arrearages on our common units. This test was met upon the payment of the distribution for the first quarter of 2019. Accordingly, 96,328,836 subordinated units converted into 96,328,836 common units on May 24, 2019 and common units are no longer entitled to arrearages.

Series A Redeemable Preferred Units

Until March 31, 2018, the holders of our outstanding Series A redeemable preferred units had the option to elect to have us redeem, effective as of December 31, 2017, their Series A redeemable preferred units at face value, plus any accrued and unpaid distributions. All Series A redeemable preferred units not redeemed by March 31, 2018 automatically converted to common and subordinated units effective as of January 1, 2018 or as soon as practicable thereafter. Therefore, there are currently no Series A redeemable preferred units outstanding.

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 the sixth anniversary of November 28, 2017 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.

ITEM 6. SELECTED FINANCIAL DATA

The financial information below should be read in conjunction with “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Part II, Item 8. Financial Statements and Supplementary Data” of this Annual Report.

	At December 31,				
	2020	2019	2018	2017	2016
	(in thousands, except per unit amounts)				
Total revenue	$ 342,751	$ 487,821	$ 609,568	$ 429,659	$ 260,833
Net income (loss)	121,819	214,368	295,560	157,153	20,188
Net income (loss) attributable to the general partner and common units and subordinated units	100,819	193,368	274,511	152,145	14,437
Net income (loss) attributable to limited partners per common and subordinated unit (basic)[1]					
Per common unit (basic)	$ 0.49	$ 1.01	$ 1.46	$ 1.01	$ 0.26
Per subordinated unit (basic)	—	0.64	1.25	0.56	(0.11)
Net income (loss) attributable to limited partners per common and subordinated unit (diluted)[1]					
Per common unit (diluted)	$ 0.49	$ 1.01	$ 1.45	$ 1.01	$ 0.26
Per subordinated unit (diluted)	—	0.64	1.25	0.56	(0.11)
Cash distributions declared per common and subordinated unit					
Per common unit	$ 0.68	$ 1.48	$ 1.33	$ 1.20	$ 1.10
Per subordinated unit	—	0.74	1.13	0.79	0.74
Total assets[2]	$ 1,243,978	$ 1,545,208	$ 1,750,124	$ 1,576,451	$ 1,128,827
Long-term debt	121,000	394,000	410,000	388,000	316,000
Total mezzanine equity	298,361	298,361	298,361	322,422	54,015

[1] See Note 13 – Earnings Per Unit in the consolidated financial statements included elsewhere in this Annual Report.

[2] We recorded noncash impairments of oil and natural gas properties in the amounts of $51.0 million and $6.8 million for the years ended December 31, 2020 and 2016, respectively. We did not have impairments of oil and natural gas properties for the years ended 2019, 2018, and 2017.

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 2020 and 2019. For the discussion of changes from 2018 to 2019 and other financial information related to 2018, refer to "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our 2019 Annual Report on Form 10-K, which was filed with the SEC on February 25, 2020.

Overview

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

As of December 31, 2020, our mineral and royalty interests were located in 41 states in the continental United States including all of the major onshore producing basins. These non-cost-bearing interests include ownership in over 70,000 producing wells. We also own non-operated working interests, a significant portion of which are on our positions where we also have a mineral and royalty interest. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when control of the oil and natural gas produced is transferred to the customer and collectability of the sales price is reasonably assured. Our other sources of revenue include mineral lease bonus and delay rentals, which are recognized as revenue according to the terms of the lease agreements.

Recent Developments

Asset Sales

In July 2020, we closed two separate divestitures of certain mineral and royalty properties in the Permian Basin for total proceeds, after final closing adjustments, of $150.6 million. The proceeds were used to reduce outstanding borrowings under our Credit Facility.

One of these transactions, effective May 1, 2020, involved the sale of our mineral and royalty interests in specific tracts in Midland County, Texas 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 our Delaware Basin and Midland Basin positions for net proceeds of approximately $96.1 million. We estimate the production associated with the properties sold, in total, to be approximately 1,800 Boe per day at the time of the sale.

COVID-19 Pandemic and Commodity Prices

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

The impact of the COVID-19 pandemic has negatively affected the oil and natural gas business environment, primarily by causing a reduction in commercial activity and travel worldwide thereby lowering energy demand. This, in turn, has resulted in significantly lower market prices for oil, natural gas, and natural gas liquids ("NGLs"). While we use derivative instruments to partially mitigate the impact of commodity price volatility, our revenues and operating results depend significantly upon the prevailing prices for oil and natural gas. The current price environment has caused many of our operators to reduce their drilling and completion activity on our acreage, and caused some of our operators to temporarily shut-in production from existing wells, both of which negatively impact our production volumes. While we believe most of the shut-in production has been brought back on-line, drilling and completion activity remains depressed relative to pre-pandemic levels.

The current price environment, including the sharp decline in oil prices that began in March 2020, also caused us to determine that certain depletable units consisting of mature oil producing properties were impaired as of March 31, 2020. Therefore, we recognized impairment of oil and natural gas properties of $51.0 million in the first quarter of 2020. Additionally, the borrowing base under the Credit Facility, which takes into consideration the estimated loan value of our oil and natural gas properties, was reduced from $650.0 million to $460.0 million, effective May 1, 2020. Effective July 21, 2020, in connection with the closing of our two asset sales in the Permian Basin, the borrowing base was further reduced to $430.0 million. Effective November 3, 2020, the most recent borrowing base redetermination reduced the borrowing base to $400.0 million. In a prolonged period of low commodity prices, we may be required to impair additional properties and the borrowing base under our Credit Facility could be further reduced. In light of the challenging business environment and uncertainty caused by the pandemic, the board of directors of our general partner (the "Board") also approved a reduction in the quarterly distribution for the first quarter of 2020 to increase the amount of retained free cash flow for debt reduction and balance sheet protection. The Board approved increases to the quarterly distribution for the second and fourth quarters of 2020, but the distribution remains below 2019 levels.

Shelby Trough Update

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

On June 10, 2020, we entered into a new incentive agreement with XTO Energy Inc. ("XTO") with respect to certain drilled but uncompleted wells ("DUCs") in our Shelby Trough acreage in San Augustine County, Texas. The agreement allows for royalty relief on 13 existing DUCs if XTO completes and turns the wells to sales by March 31, 2021, and complements the recent development agreement with Aethon covering our Shelby Trough acreage in Angelina County towards our goal of reviving volume growth from the area. As of January 18, 2021, XTO has turned all 13 DUCs to sales.

Austin Chalk Update

We are currently working with several operators to test and develop areas of the Austin Chalk in East Texas where we have significant acreage positions. Recent drilling results have shown that advances in fracturing and other completion techniques can dramatically improve well performance from the Austin Chalk formation. In February of 2021, we entered into an agreement with a large, publicly traded independent operator by which the operator will undertake a program to drill, test, and complete wells in the Austin Chalk formation on certain of our acreage in East Texas. If successful, the operator has the option to expand its drilling program over a significant acreage position owned and controlled by us.

We are also working with existing operators across our East Texas Austin Chalk position to encourage new development utilizing current completion techniques.

Business Environment

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

COVID-19 Pandemic and Market Conditions

The COVID-19 pandemic and related economic repercussions have resulted in a significant reduction in demand for and prices of oil, natural gas and NGLs. In the first quarter of 2020 and into the second quarter of 2020, oil prices fell sharply, due in part to significantly decreased demand as a result of the COVID-19 pandemic and the announcement by Saudi Arabia of a significant increase in its maximum oil production capacity as well as the announcement by Russia that previously agreed upon oil production cuts between members of the Organization of the Petroleum Exporting Countries and its broader partners (“OPEC+”) would expire on April 1, 2020, and the ensuing expiration thereof. Agreed-upon production cuts by OPEC+ along with declining U.S. production have helped to correct the supply and demand imbalance; however, these reductions are not expected to be enough in the near-term to offset the significant inventory build caused by demand destruction from the COVID-19 pandemic. These market conditions have resulted in a decline in drilling activity as operators revise their capital budgets downward and adjust their operations in response to lower commodity prices. Crude oil and natural gas spot prices in early 2021 and contract future prices for the full year 2021 have improved significantly from levels seen in the second quarter of 2020; however, drilling activity remains depressed relative to levels experienced in 2018 and 2019. Given the dynamic nature of these events, we cannot reasonably estimate the period of time that the COVID-19 pandemic and related market conditions will persist.

Commodity Prices and Demand

Oil and natural gas prices have been historically volatile based upon the dynamics of supply and demand. The EIA forecasts that WTI oil prices will average approximately $49.70 per Bbl in 2021 and $49.81 per Bbl in 2022. During the year ended December 31, 2020, the WTI oil spot price reached a high of $63.27 per Bbl on January 6, 2020, but decreased to a low of $8.91 per Bbl on April 21, 2020. This excludes the period in April 2020 when WTI briefly traded in negative territory.

The EIA forecasts that the Henry Hub spot natural gas price will average $3.01 per MMBtu for 2021 and $3.27 per MMBtu for 2022. During the year ended December 31, 2020, Henry Hub spot natural gas prices ranged from a high of $3.14 per MMBtu on October 26, 2020 to a low of $1.33 per MMBtu on September 21, 2020.

To manage the variability in cash flows associated with the projected sale of our oil and natural gas production, we use various derivative instruments, which have recently consisted of fixed-price swap contracts and costless collar contracts.

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

	2020			
Benchmark Prices	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot crude oil ($/Bbl)[1]	$ 48.35	$ 40.05	$ 39.27	$ 20.51
Henry Hub spot natural gas ($/MMBtu)[1]	$ 2.36	$ 1.66	$ 1.76	$ 1.71

[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:

	2020			
U.S. Rotary Rig Count[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	267	183	188	624
Natural gas	83	75	75	102
Other	1	3	2	2
Total	351	261	265	728

[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 2021, at almost 1.6 Tcf, or 12% lower than the five-year average. The EIA expects inventories will reach almost 3.6 Tcf at the end of October 2021, which would be 5% lower than the five-year average.

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

	2020			
Region[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
	(Bcf)			
East	771	890	655	385
Midwest	930	1,053	747	472
Mountain	197	235	177	92
Pacific	283	318	308	200
South Central	1,166	1,313	1,221	857
Total	3,347	3,809	3,108	2,006

[1] Source: EIA

How We Evaluate Our Operations

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

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

Volumes of Oil and Natural Gas Produced

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

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

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

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

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

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

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

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

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

Hedging

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

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

We may employ contractual arrangements other than fixed-price swap contracts and costless collar contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue. Our open oil and natural gas derivative contracts as of December 31, 2020 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 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, 2020, we had hedged 98% of our available oil and condensate hedge volumes and 80% of our available natural gas hedge volumes for 2021.

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

Non-GAAP Financial Measures

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

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

Adjusted EBITDA and Distributable cash flow should not be considered an alternative to, or more meaningful than, net income (loss), income (loss) from operations, cash flows from operating activities, or any other measure of financial performance presented in accordance with generally accepted accounting principles ("GAAP") in the 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,	
	2020	2019
	(in thousands)	
Net income (loss)	$ 121,819	$ 214,368
Adjustments to reconcile to Adjusted EBITDA:		
Depreciation, depletion, and amortization	82,018	109,584
Impairment of oil and natural gas properties	51,031	—
Interest expense	10,408	21,435
Income tax expense (benefit)	8	(335)
Accretion of asset retirement obligations	1,131	1,117
Equity-based compensation	3,727	20,484
Unrealized (gain) loss on commodity derivative instruments	35,238	32,817
(Gain) loss on sale of assets, net	(24,045)	—
Adjusted EBITDA	281,335	399,470
Adjustments to reconcile to Distributable cash flow:		
Change in deferred revenue	(391)	42
Cash interest expense	(9,364)	(20,394)
Estimated replacement capital expenditures[1]	—	(2,750)
Preferred unit distributions	(21,000)	(21,000)
Restructuring charges	4,815	—
Distributable cash flow	$ 255,395	$ 355,368

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

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

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

	Year Ended December 31,			
	2020	2019	Variance	
	(dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	3,895	4,777	(882)	(18.5)%
Natural gas (MMcf)[1]	67,945	77,635	(9,690)	(12.5)%
Equivalents (MBoe)	15,219	17,716	(2,497)	(14.1)%
Equivalents/day (MBoe)	41.6	48.5	(6.9)	(14.2)%
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 38.16	$ 55.20	$ (17.04)	(30.9)%
Natural gas ($/Mcf)[1]	2.04	2.57	(0.53)	(20.6)%
Equivalents ($/Boe)	$ 18.89	$ 26.13	$ (7.24)	(27.7)%
Revenue:				
Oil and condensate sales	$ 148,631	$ 263,678	$ (115,047)	(43.6)%
Natural gas and natural gas liquids sales[1]	138,926	199,265	(60,339)	(30.3)%
Lease bonus and other income	9,083	29,833	(20,750)	(69.6)%
Revenue from contracts with customers	296,640	492,776	(196,136)	(39.8)%
Gain (loss) on commodity derivative instruments	46,111	(4,955)	51,066	NM[2]
Total revenue	$ 342,751	$ 487,821	$ (145,070)	(29.7)%
Operating expenses:				
Lease operating expense	$ 14,022	$ 17,665	$ (3,643)	(20.6)%
Production costs and ad valorem taxes	43,473	60,533	(17,060)	(28.2)%
Exploration expense	29	397	(368)	(92.7)%
Depreciation, depletion, and amortization	82,018	109,584	(27,566)	(25.2)%
Impairment of oil and natural gas properties	51,031	—	51,031	NM[2]
General and administrative	42,983	63,353	(20,370)	(32.2)%
Other expense:				
Interest expense	10,408	21,435	(11,027)	(51.4)%

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

[2] Not meaningful.

<u>Revenue</u>

Total revenue for the year ended December 31, 2020 decreased compared to the year ended December 31, 2019. The decrease in total revenue from the corresponding period is primarily due to a decrease in oil and condensate sales and natural gas and NGL sales as a result of lower realized commodity prices and lower production volumes, and a decrease in lease bonus and other income. The overall decrease was partially offset by a gain on commodity derivative instruments in 2020 compared to a loss in 2019.

Oil and condensate sales. Oil and condensate sales for the year ended December 31, 2020 were lower than the corresponding period in 2019 due to decreased production volumes and lower realized commodity prices. The decrease in oil and condensate production was primarily driven by lower production in the Permian Basin and the Bakken/Three Forks. Our mineral and royalty interest oil and condensate volumes accounted for 92% of total oil and condensate volumes for each of the years ended December 31, 2020 and 2019.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased for the year ended December 31, 2020 as compared to the year ended December 31, 2019 due to lower realized commodity prices and lower production volumes. The decrease in natural gas production was driven by lower volumes in the Haynesville/Bossier play primarily due to reduced drilling activity and shut-in production volumes associated with the completion of certain DUCs on our Shelby Trough acreage. Mineral and royalty interest production accounted for 76% and 69% of our natural gas volumes for the years ended December 31, 2020 and 2019, respectively.

Gain (loss) on commodity derivative instruments. During 2020, we recognized a gain from our commodity derivative instruments compared to a loss in 2019. Cash settlements we receive represent realized gains, while cash settlements we pay represent realized losses related to our commodity derivative instruments. In addition to cash settlements, we also recognize fair value changes on our commodity derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves. During 2020, we recognized $81.3 million of realized gains and $35.2 million of unrealized losses from our commodity derivatives, compared to $27.9 million of realized gains and $32.8 million of unrealized losses in 2019. The unrealized losses on our commodity contracts in 2020 were primarily driven by changes in the forward commodity price curves for oil and natural gas. The unrealized losses on our commodity contracts in 2019 were primarily driven by changes in the forward commodity price curves for oil, partially offset by changes in the forward commodity price curves for natural gas.

Lease bonus and other income. 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, 2020, as compared to the same period in 2019. Leasing activity in the Permian Basin, Haynesville/Bossier, Green River Basin, and Bakken/Three Forks plays as well as certain surface leases in Polk County, Texas made up the majority of lease bonus and other income in 2020. Leasing activity in the Bakken/Three Forks, Haynesville/Bossier, Permian Basin, and Woodbine plays, as well as proceeds from the settlement of a dispute with one of our operators, made up the majority of lease bonus and other income in 2019.

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 2020 as compared to 2019, primarily due to lower nonrecurring service-related expenses, including workovers, as well as a decrease in variable costs as a result of lower production from our non-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, 2020, production and ad valorem taxes decreased as compared to the year ended December 31, 2019, as a result of lower commodity prices and lower production volumes.

Exploration expense. Exploration expense typically consists of dry-hole expenses, delay rentals, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense for 2020 was minimal. Exploration expense for 2019 primarily consisted of costs incurred to acquire 3-D seismic information related to our mineral and royalty interests from a third-party service provider.

Depreciation, depletion, and amortization. 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, 2020 as compared to 2019, primarily due to lower production volumes and a reduction in cost basis with lower corresponding reduction in proved developed producing reserve quantities. The reduction in cost basis is primarily due to oil and natural gas property divestitures, continued depreciation, depletion, and amortization, and oil and natural gas property impairments.

Impairment of oil and natural gas properties. Individual categories of oil and natural gas properties are assessed periodically to determine if the net book value for these properties has been impaired. Management periodically conducts an in-depth evaluation of the cost of property acquisitions, successful exploratory wells, development activities, unproved leasehold, and mineral interests to identify impairments. Impairments totaled $51.0 million for the year ended December 31, 2020, primarily due to declines in future expected realizable net cash flows as a result of lower commodity prices as of the measurement date of March 31, 2020. There were no impairments for 2019.

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, 2020, general and administrative expenses decreased compared to 2019, primarily due to a $8.9 million decrease in cash compensation and a $16.8 decrease in equity-based compensation. The decrease in cash compensation is primarily resulting from the broad workforce reductions in the first quarter of 2020. The decrease in equity-based compensation is due in part to these same workforce reductions but also due to downward cost revisions recognized in 2020 for performance-based incentive awards due to the decrease in our common unit price period over period. The overall decrease was partially offset by $4.8 million of restructuring charges in the first quarter of 2020 associated with the workforce reductions.

Other Expense

Interest expense. For the year ended December 31, 2020, interest expense decreased compared to 2019, primarily due to lower average outstanding borrowings and lower 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, and for investing in our business, specifically the acquisition of mineral and royalty interests and our selective participation on a non-operated working interest basis in the development of our oil and natural gas properties.

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 our future acquisitions with cash generated from operations, borrowings from our Credit Facility, and proceeds from any future issuances of equity and debt. Over the long-term, we intend to finance our working interest capital needs with our executed farmout agreements and internally-generated cash flows, although at times we may fund a portion of these expenditures through other financing sources such as borrowings under our Credit Facility. Replacement capital expenditures are expenditures necessary to replace our existing oil and natural gas reserves or otherwise maintain our asset base over the long-term. The Board established a replacement capital expenditure estimate of $11.0 million for the period of April 1, 2018 to March 31, 2019. Due to the expiration of the subordination period, we do not intend to establish a replacement capital expenditure estimate for periods subsequent to March 31, 2019.

Cash Flows

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

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

	Year Ended December 31,		
	2020	2019	Change
	(in thousands)		
Cash flows provided by operating activities	$ 281,809	$ 412,720	$ (130,911)
Cash flows provided by (used in) investing activities	151,246	(48,623)	199,869
Cash flows provided by (used in) financing activities	(439,378)	(361,392)	(77,986)

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 2020 decreased as compared to 2019. The decrease was primarily due to decreased oil and condensate sales and natural gas and NGL sales driven by lower realized commodity prices and lower production. The overall decrease was partially offset by higher net cash received on settlement of commodity derivative instruments.

Investing Activities. Net cash was provided by investing activities for 2020 as compared to net cash used in investing activities for 2019. The change was primarily due to increased proceeds from the sale of oil and natural gas properties as well as a decrease in oil and natural gas property acquisitions and additions in 2020 as compared with 2019.

Financing Activities. Cash flows used in financing activities for 2020 increased as compared to 2019. The increase was primarily due to increased net repayments under our Credit Facility in 2020 compared with 2019. The overall increase was partially offset by lower distributions to common unitholders and decreased repurchases of common units.

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 2021 capital expenditure budget associated with our non-operated working interests is expected to be approximately $5 million, net of farmout reimbursements. The majority of this capital is anticipated to be spent for working interest participation on test wells in the Austin Chalk play and the remaining will be spent for workovers on existing wells in which we own a working interest.

During 2020, we spent approximately $0.6 million associated with our non-operated working interests, net of farmout reimbursements.

During 2019, we spent approximately $4.3 million associated with our non-operated working interests, net of farmout reimbursements. The majority of this capital was spent for workovers on existing wells in which we own a working interest or for acquiring new leasehold acreage for subsequent farmout in the Haynesville/Bossier play.

Acquisitions

We had no acquisition activity during 2020,

During 2019 we spent approximately $43.1 million and issued common units valued at $0.9 million related to acquisitions of mineral and royalty interests, which also included proved oil and natural gas properties.

During 2018 we spent approximately $127.3 million and issued common units valued at $22.6 million related to acquisitions of mineral and royalty interests, which also included proved oil and natural gas properties.

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

Credit Facility

Pursuant to our $1.0 billion senior secured revolving credit agreement, as amended (the "Credit Facility"), the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base, which is determined based on the lenders' estimated value of our oil and natural gas properties. Borrowings under the Credit Facility may be used for the acquisition of properties, cash distributions, and other general corporate purposes. Our Credit Facility terminates on November 1, 2022. As of December 31, 2020, we had outstanding borrowings of $121.0 million at a weighted-average interest rate of 2.40%.

The borrowing base is redetermined semi-annually, typically in April and October of each year, by the administrative agent, taking into consideration the estimated loan value of our oil and natural gas properties consistent with the administrative agent's normal lending criteria. The administrative agent's proposed redetermined borrowing base must be approved by all lenders to increase our existing borrowing base, and by two-thirds of the lenders to maintain or decrease our existing borrowing base. In addition, we and the lenders (at the election of two-thirds of the lenders) each have discretion to have the borrowing base redetermined once 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. Effective October 23, 2019, the borrowing base redetermination reduced the borrowing base to $650.0 million. Effective May 1, 2020, the borrowing base was further reduced to $460.0 million. Effective July 21, 2020, in connection with the closing of two asset sales in the Permian Basin, the borrowing base was further reduced to $430.0 million. Effective November 3, 2020, the most recent borrowing base redetermination reduced the borrowing base to $400.0 million. The next semi-annual redetermination is scheduled for April 2021.

Outstanding borrowings under the Credit Facility bear interest at a floating rate elected by us equal to an alternative base rate (which is equal to the greatest of the Prime Rate, the Federal Funds effective rate plus 0.50%, or 1-month LIBOR plus 1.00%) or LIBOR, in each case, plus the applicable margin. Effective October 31, 2018, the applicable margin for the alternative base rate was reduced to between 0.75% and 1.75% and the applicable margin for LIBOR was reduced to between

1.75% and 2.75%. Effective November 3, 2020, the LIBOR margin was increased to between 2.00% and 3.00% and the alternative base rate margin was increased to between 1.00% and 2.00%.

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

Our credit agreement contains various affirmative, negative, and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates, and entering into certain derivative agreements, as well as require the maintenance of certain financial ratios. The credit agreement contains two financial covenants: total debt to EBITDAX of 3.5:1.0 or less and a current ratio of 1.0:1.0 or greater as defined in the credit agreement. Distributions are not permitted if there is a default under the credit agreement (including the failure to satisfy one of the financial covenants) or during any time that our borrowing base is lower than the loans outstanding under the credit agreement. The lenders have the right to accelerate all of the indebtedness under the credit agreement upon the occurrence and during the continuance of any event of default, and the credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. As of December 31, 2020, we were in compliance with all debt covenants.

On July 27, 2017, the U.K. Financial Conduct Authority announced that it intends to stop persuading or compelling banks to submit LIBOR rates after 2021. Our Credit Facility includes provisions to determine a replacement rate for LIBOR if necessary during its term, which require that we and our lenders agree upon a replacement rate based on the then-prevailing market convention for similar agreements. We currently do not expect the transition from LIBOR to have a material impact on us. However, if clear market standards and replacement methodologies have not developed as of the time LIBOR becomes unavailable, we may have difficulty reaching agreement on acceptable replacement rates under our Credit Facility. In the event that we do not reach agreement on an acceptable replacement rate for LIBOR, outstanding borrowings under the Credit Facility would revert to a floating rate equal to the alternative base rate (which, as of the time that LIBOR becomes unavailable, is equal to the greater of the Prime Rate and the Federal Funds effective rate plus 0.50%) plus the applicable margin for the alternative base rate which ranges between 1.00% and 2.00%. If we are unable to negotiate replacement rates on favorable terms, it could have a material adverse effect on our financial condition, results of operations, and cash distributions to unitholders.

Contractual Obligations

The following table summarizes our minimum payments as of December 31, 2020 (in thousands):

		Payments due by period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Credit facility	$ 121,000	$ —	$ 121,000	$ —	$ —
Operating lease obligations	4,288	1,401	2,884	3	—
Purchase commitments	998	884	114	—	—
Total	$ 126,286	$ 2,285	$ 123,998	$ 3	$ —

Off-Balance Sheet Arrangements

At December 31, 2020, we did not have any material off-balance sheet arrangements.

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, valuation of future asset retirement obligations ("ARO"), 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 geological structural feature or stratigraphic condition, such as a reservoir or field, 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 $81.3 million, $109.0 million, and $122.5 million for the years ended December 31, 2020, 2019, and 2018, 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. We determined these events and circumstances indicated a possible decline in the recoverability of the carrying value of certain proved properties and recoverability testing determined that certain depletable units consisting of mature oil producing properties were impaired as of March 31,2020. We recognized $51.0 million of impairment of proved oil and natural gas properties for the year ended December 31, 2020. There was no impairment of proved oil and natural gas properties for the years ended December 31, 2019 and 2018.

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, 2020, 2019, and 2018.

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, 2020 reserve report. Applying this discount results in an approximate 4% reduction of estimated proved reserve volumes as compared to the undiscounted pricing scenario used in our December 31, 2020 reserve report prepared by NSAI.

Asset Retirement Obligations

Under various contracts, permits, and regulations, we have legal obligations to restore the land at the end of operations at certain properties where we own non-operated working interests. Estimating the future restoration costs necessary for this accounting calculation is difficult. Most of these restoration obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what practices and criteria must be met when the event actually occurs. Asset-restoration technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into the valuation of the obligation, including discount and inflation rates, are also subject to change.

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, we capitalize 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.

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. We adopted ASC 606 using the modified retrospective method, which was applied to all existing contracts for which all (or substantially all) of the revenue had not been recognized under legacy revenue guidance as of the date of adoption, January 1, 2018.

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. Overall, there were no material changes in the timing of the satisfaction of our performance obligations or the allocation of the transaction price to our performance obligations in applying the guidance in ASC 606 as compared to legacy GAAP.

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, 2020 and 2019, 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 its 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 expected to vest 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 that, based on our estimate, are probable to vest, 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 that are expected to vest 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.

New and Revised Financial Accounting Standards

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure is the pricing of oil, natural gas, and NGLs produced by our operators. Realized prices are primarily driven by the prevailing global prices for oil and prices for natural gas and NGLs in the United States. Prices for oil, natural gas, and NGLs have been volatile for several years, and we expect this unpredictability to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative financial instruments to reduce our exposure to price volatility of oil and natural gas. The counterparties to the contracts are unrelated third parties. The contracts settle monthly in cash based 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 declined in recent years. 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, 2020. Applying this discount results in an approximate 4% reduction of proved reserve volumes as compared to the undiscounted December 31, 2020 SEC pricing scenario.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of December 31, 2020, we had eight 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, 2020, we had $121.0 million of outstanding borrowings under our Credit Facility, bearing interest at a weighted-average interest rate of 2.4%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of $1.2 million for the year ended December 31, 2020, assuming that our indebtedness remained constant throughout the period. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have any interest rate hedges in place.

ITEM 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, 2020 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, 2020, 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, 2020.

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, 2020, 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, 2020, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

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 2021 Annual Meeting of Limited Partners (“2021 Proxy Statement”), which will be filed with the SEC not later than 120 days after December 31, 2020.

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 2021 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2020.

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 2021 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2020.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2020.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by this item is incorporated by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2020.

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)).
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^	Form of IPO Award Grant Notice and Award Agreement for Senior Management (Restricted Units) (incorporated herein by reference to Exhibit 10.9 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on April 13, 2015 (SEC File No. 333-202875)).
10.8^	Form of IPO Award Grant Notice and Award Agreement for Senior Management (Performance Units) (incorporated herein by reference to Exhibit 10.10 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on April 13, 2015 (SEC File No. 333-202875)).
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) under the Black Stone Minerals, L.P. Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on February 19, 2016 (SEC File No. 001-37362).
10.13^	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)).
10.14	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 23, 2021	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 23, 2021
/s/ Jeffrey P. Wood Jeffrey P. Wood	President and Chief Financial Officer (Principal Financial Officer)	February 23, 2021
/s/ Dawn K. Smajstrla Dawn K. Smajstrla	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 23, 2021
/s/ Carin M. Barth Carin M. Barth	Director	February 23, 2021
/s/ D. Mark DeWalch D. Mark DeWalch	Director	February 23, 2021
/s/ Jerry V. Kyle, Jr. Jerry V. Kyle, Jr.	Director	February 23, 2021
/s/ Michael C. Linn Michael C. Linn	Director	February 23, 2021
/s/ John H. Longmaid John H. Longmaid	Director	February 23, 2021
/s/ William N. Mathis William N. Mathis	Director	February 23, 2021
/s/ William E. Randall William E. Randall	Director	February 23, 2021
/s/ Alexander D. Stuart Alexander D. Stuart	Director	February 23, 2021
/s/ Allison K. Thacker Allison K. Thacker	Director	February 23, 2021

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, 2020 and 2019, the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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 23, 2021, 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") and Impairment of Oil and Natural Gas Properties
Description of the Matter	At December 31, 2020, the net book value of the Partnership's oil and natural gas properties was $1,170 million, and depreciation, depletion and amortization ("DD&A") expense related to the Partnership's producing oil and natural gas properties was $81 million and impairment of oil and natural gas properties was $51 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 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. When events or changes in circumstances indicate that the carrying amount of oil and natural gas properties may not be recoverable, the Partnership compares the undiscounted projected future cash flows to the unamortized carrying amount on a depletable unit basis. If the carrying amount exceeds its projected undiscounted future cash flows, the carrying amount is written down to its fair value. 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. 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 evaluating geological and engineering data used to estimate oil and natural gas reserves. Estimating reserves also requires the selection of inputs, including oil and natural gas price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating oil and natural gas reserves, management used independent petroleum engineers to prepare the oil and natural gas reserve estimates as of December 31, 2020.

	Auditing the Partnership's DD&A and impairment calculations 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 and impairment, 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 prepare the oil and natural gas reserve 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 agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. We also tested the mathematical accuracy of the DD&A and impairment calculations, including comparing the proved oil and natural gas reserve amounts used in the calculations to the Partnership's reserve report.
	Revenues from Contracts with Customers Accrual
Description of the Matter	At December 31, 2020, the Partnership had $58 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 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 agreeing them to source documentation and evaluating corroborative and contrary evidence. These inputs included oil and natural gas price assumptions and production estimates. Additionally, we assessed the completeness and accuracy of the revenues from contracts with customers accrual through analytic procedures, and 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 23, 2021

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, 2020, 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, 2020, 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, 2020 and 2019, the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2020, and the related notes and our report dated February 23, 2021, 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 23, 2021

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

	As of December 31,	
	2020	**2019**
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,796	$ 8,119
Accounts receivable	61,908	78,214
Commodity derivative assets	1,149	14,790
Prepaid expenses and other current assets	1,668	1,168
TOTAL CURRENT ASSETS	66,521	102,291
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $937,464 and $1,073,447 at December 31, 2020 and 2019, respectively	3,157,818	3,302,340
Accumulated depreciation, depletion, amortization, and impairment	(1,987,332)	(1,870,412)
Oil and natural gas properties, net	1,170,486	1,431,928
Other property and equipment, net of accumulated depreciation of $12,292 and $11,622 at December 31, 2020 and 2019, respectively	1,650	2,300
NET PROPERTY AND EQUIPMENT	1,172,136	1,434,228
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	5,321	8,689
TOTAL ASSETS	$ 1,243,978	$ 1,545,208
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 3,407	$ 5,309
Accrued liabilities	15,568	22,702
Commodity derivative liabilities	19,318	159
Other current liabilities	1,654	1,633
TOTAL CURRENT LIABILITIES	39,947	29,803
LONG-TERM LIABILITIES		
Credit facility	121,000	394,000
Accrued incentive compensation	766	2,110
Commodity derivative liabilities	1,848	18
Asset retirement obligations	17,377	15,653
Other long-term liabilities	4,073	6,820
TOTAL LIABILITIES	185,011	448,404
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, 2020 and 2019, respectively	298,361	298,361
EQUITY		
Partners' equity — general partner interest	—	—
Partners' equity — common units, 206,749 and 205,960 units outstanding at December 31, 2020 and 2019, respectively	760,606	798,443
TOTAL EQUITY	760,606	798,443
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,243,978	$ 1,545,208

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

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

	Year Ended December 31,		
	2020	**2019**	**2018**
REVENUE			
Oil and condensate sales	$ 148,631	$ 263,678	$ 310,278
Natural gas and natural gas liquids sales	138,926	199,265	248,243
Lease bonus and other income	9,083	29,833	36,216
Revenue from contracts with customers	296,640	492,776	594,737
Gain (loss) on commodity derivative instruments	46,111	(4,955)	14,831
TOTAL REVENUE	342,751	487,821	609,568
OPERATING (INCOME) EXPENSE			
Lease operating expense	14,022	17,665	18,415
Production costs and ad valorem taxes	43,473	60,533	64,364
Exploration expense	29	397	7,943
Depreciation, depletion, and amortization	82,018	109,584	122,653
Impairment of oil and natural gas properties	51,031	—	—
General and administrative	42,983	63,353	76,712
Accretion of asset retirement obligations	1,131	1,117	1,103
(Gain) loss on sale of assets, net	(24,045)	—	(3)
TOTAL OPERATING EXPENSE	210,642	252,649	291,187
INCOME (LOSS) FROM OPERATIONS	132,109	235,172	318,381
OTHER INCOME (EXPENSE)			
Interest and investment income	35	159	183
Interest expense	(10,408)	(21,435)	(20,756)
Other income (expense)	83	472	(2,248)
TOTAL OTHER EXPENSE	(10,290)	(20,804)	(22,821)
NET INCOME (LOSS)	121,819	214,368	295,560
Net (income) loss attributable to noncontrolling interests	—	—	(24)
Distributions on Series A redeemable preferred units	—	—	(25)
Distributions on Series B cumulative convertible preferred units	(21,000)	(21,000)	(21,000)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	$ 100,819	$ 193,368	$ 274,511
ALLOCATION OF NET INCOME (LOSS):			
General partner interest	$ —	$ —	$ —
Common units	100,819	169,375	154,662
Subordinated units	—	23,993	119,849
	$ 100,819	$ 193,368	$ 274,511
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:			
Per common unit (basic)	$ 0.49	$ 1.01	$ 1.46
Weighted average common units outstanding (basic)	206,705	168,230	106,064
Per subordinated unit (basic)	$ —	$ 0.64	$ 1.25
Weighted average subordinated units outstanding (basic)	—	37,740	96,099
Per common unit (diluted)	$ 0.49	$ 1.01	$ 1.45
Weighted average common units outstanding (diluted)	206,819	168,376	121,264
Per subordinated unit (diluted)	$ —	$ 0.64	$ 1.25
Weighted average subordinated units outstanding (diluted)	—	37,740	96,346

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	Subordinated units	Partners' equity—common units	Partners' equity—subordinated units	Noncontrolling interests	Total equity
BALANCE AT DECEMBER 31, 2017	103,456	95,388	$ 603,116	$ 164,138	$ 867	$ 768,121
Conversion of Series A redeemable preferred units	736	964	10,498	13,750	—	24,248
Repurchases of common and subordinated units	(623)	(23)	(10,879)	(342)	—	(11,221)
Purchase of noncontrolling interests	—	—	(1,026)	—	(680)	(1,706)
Issuance of common units, net of offering costs	2,244	—	40,537	—	—	40,537
Issuance of common units for property acquisitions	1,234	—	22,657	—	—	22,657
Restricted units granted, net of forfeitures	1,316	—	—	—	—	—
Equity-based compensation	—	—	40,733	219	—	40,952
Distributions	—	—	(141,777)	(108,174)	(211)	(250,162)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(3,698)	—	—	(3,698)
Distributions on Series A redeemable preferred units	—	—	(13)	(12)	—	(25)
Distributions on Series B cumulative convertible preferred units	—	—	(21,000)	—	—	(21,000)
Net income (loss)	—	—	175,675	119,861	24	295,560
BALANCE AT DECEMBER 31, 2018	108,363	96,329	$ 714,823	$ 189,440	$ —	$ 904,263
Conversion of subordinated units	96,329	(96,329)	142,149	(142,149)	—	—
Repurchases of common and subordinated units	(966)	—	(16,287)	—	—	(16,287)
Issuance of common units, net of offering costs	—	—	(43)	—	—	(43)
Issuance of common units for property acquisitions	57	—	943	—	—	943
Restricted units granted, net of forfeitures	2,177	—	—	—	—	—
Equity-based compensation	—	—	23,490	—	—	23,490
Distributions	—	—	(233,155)	(71,284)	—	(304,439)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(2,852)	—	—	(2,852)
Distributions on Series B cumulative convertible preferred units	—	—	(21,000)	—	—	(21,000)
Net income (loss)	—	—	190,375	23,993	—	214,368
BALANCE AT DECEMBER 31, 2019	205,960	—	$ 798,443	$ —	$ —	$ 798,443
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

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,		
	2020	**2019**	**2018**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 121,819	$ 214,368	$ 295,560
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	82,018	109,584	122,653
Impairment of oil and natural gas properties	51,031	—	—
Accretion of asset retirement obligations	1,131	1,117	1,103
Amortization of deferred charges	1,044	1,041	905
(Gain) loss on commodity derivative instruments	(46,111)	4,955	(14,831)
Net cash (paid) received on settlement of commodity derivative instruments	81,349	27,862	(38,235)
Equity-based compensation	3,727	20,484	30,134
Exploratory dry hole expense	—	3	6,785
Deferred rent	—	—	1,283
(Gain) loss on sale of assets, net	(24,045)	—	(3)
Changes in operating assets and liabilities:			
Accounts receivable	16,494	35,044	(31,531)
Prepaid expenses and other current assets	(500)	(167)	210
Accounts payable, accrued liabilities, and other	(5,929)	(1,191)	11,474
Settlement of asset retirement obligations	(219)	(380)	(129)
NET CASH PROVIDED BY OPERATING ACTIVITIES	281,809	412,720	385,378
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisitions of oil and natural gas properties	(28)	(43,051)	(124,081)
Additions to oil and natural gas properties	(3,969)	(64,782)	(166,970)
Additions to oil and natural gas properties leasehold costs	(798)	(980)	(6,263)
Purchases of other property and equipment	(21)	(2,488)	(21)
Proceeds from the sale of oil and natural gas properties	151,864	1,174	9,009
Proceeds from farmouts of oil and natural gas properties	4,198	61,504	124,522
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	151,246	(48,623)	(163,804)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from issuance of common units, net of offering costs	—	(43)	40,537
Distributions to common and subordinated unitholders	(140,343)	(304,439)	(250,121)
Distributions to Series A redeemable preferred unitholders	—	—	(690)
Distributions to Series B cumulative convertible preferred unitholders	(21,000)	(21,000)	(17,675)
Distributions to noncontrolling interests	—	—	(211)
Distributions equivalents paid	—	(2,981)	—
Redemption of Series A redeemable preferred units	—	—	(2,115)
Repurchases of common and subordinated units	(5,035)	(16,929)	(10,579)
Purchase of noncontrolling interests	—	—	(1,706)
Borrowings under credit facility	160,000	334,500	373,500
Repayments under credit facility	(433,000)	(350,500)	(351,500)
Debt issuance costs and other	—	—	(1,242)
NET CASH (USED IN) PROVIDED BY FINANCING ACTIVITIES	(439,378)	(361,392)	(221,802)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(6,323)	2,705	(228)
Cash and cash equivalents — beginning of the year	8,119	5,414	5,642
Cash and cash equivalents — end of the year	$ 1,796	$ 8,119	$ 5,414
SUPPLEMENTAL DISCLOSURE			
Interest paid	$ 9,449	$ 20,470	$ 19,761

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, valuation of future asset retirement obligations (“ARO”), 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,	
	2020	2019
	(in thousands)	
Accounts receivable:		
Revenues from contracts with customers	$ 58,181	$ 71,022
Other	3,727	7,192
Total accounts receivable	$ 61,908	$ 78,214

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 leasehold 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 geological structural feature or stratigraphic condition, such as a reservoir or field, 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 $81.3 million, $109.0 million, and $122.5 million for the years ended December 31, 2020, 2019, and 2018, 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 as of March 31, 2020. The Partnership recognized $51.0 million of impairment of proved oil and natural gas properties for the year ended December 31, 2020. There was no impairment of proved oil and natural gas properties for the years ended December 31, 2019 and 2018. 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, 2020, 2019, and 2018.

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

Other Property and Equipment

Other property and equipment includes furniture, fixtures, office equipment, leasehold improvements, and computer software and is stated at historical cost. Depreciation and amortization are calculated using the straight-line method over expected useful lives ranging from 3 years to 7 years. Depreciation and amortization expense totaled $0.7 million, $0.6 million, and $0.2 million for the years ended December 31, 2020, 2019, and 2018, 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,	
	2020	2019
	(in thousands)	
Accrued liabilities:		
Accrued capital expenditures	$ —	$ 2,019
Accrued incentive compensation	5,058	9,057
Accrued property taxes	8,432	8,131
Accrued other	2,078	3,495
Total accrued liabilities	$ 15,568	$ 22,702

Debt Issuance Costs

Debt issuance costs consist of costs directly associated with obtaining credit with financial institutions. These costs are capitalized and are amortized on a straight-line basis over the life of the credit agreement, which approximates the effective-interest method. Any unamortized debt issuance costs are expensed in the year when the associated debt instrument is terminated. Amortization expense for debt issuance costs was $1.0 million, $1.0 million, and $0.9 million for the years ended December 31, 2020, 2019, and 2018, 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, 2020, none of the Partnership's leases were classified as financing leases.

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. The Partnership adopted ASC 606 using the modified retrospective method, which was applied to all existing contracts for which all (or substantially all) of the revenue had not been recognized under legacy revenue guidance as of the date of adoption, January 1, 2018.

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

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

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

Lease bonus and other income

Given that the Partnership does not recognize lease bonus or other income until a lease agreement has been executed, at which point its performance obligation has been satisfied, and payment is received, the Partnership does not record revenue for unsatisfied or partially unsatisfied performance obligations as of the end of the reporting period. Overall, there were no material changes in the timing of the satisfaction of the Partnership's performance obligations or the allocation of the transaction price to its performance obligations in applying the guidance in ASC 606 as compared to legacy GAAP.

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, 2020 and 2019, 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, 2020 and 2019 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 General and administrative expense on the consolidated statements of operations. See Note 9 – Incentive Compensation for additional discussion.

Recent Accounting Pronouncements

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

NOTE 3 — ASSET RETIREMENT OBLIGATIONS

The 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,	
	2020	2019
	(in thousands)	
Beginning asset retirement obligations	$ 16,084	$ 15,475
Liabilities incurred	1,030	209
Liabilities settled	(324)	(1,073)
Accretion expense	1,131	1,117
Revisions in estimated costs	(151)	976
Dispositions	(53)	(620)
Ending asset retirement obligations	$ 17,717	$ 16,084
Current asset retirement obligations	$ 340	$ 431
Non-current asset retirement obligations	$ 17,377	$ 15,653

NOTE 4 — OIL AND NATURAL GAS PROPERTIES

Divestitures

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.

2020 Acquisitions

The Partnership had no acquisition activity during the year ended December 31, 2020.

2019 Acquisitions

During the year ended December 31, 2019, the Partnership closed on multiple acquisitions of mineral and royalty interests for total consideration of $44.0 million. Acquisitions that were considered business combinations were primarily located in the Permian Basin. These acquisitions were funded with borrowings under the Partnership's Credit Facility (as defined in Note 8 - Credit Facility) and funds from operating activities. Acquisition related costs of $0.1 million were expensed and included in the General and administrative expense line item of the consolidated statement of operations for the year ended December 31, 2019. The following table summarizes these acquisitions:

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

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

2018 Acquisitions

During the year ended December 31, 2018, the Partnership closed on multiple acquisitions of mineral and royalty interests for total consideration of $149.9 million.

Acquisitions that were considered business combinations were primarily located in the Permian Basin. The cash portion of the consideration paid for these acquisitions was funded with borrowings under the Partnership's Credit Facility and funds from operating activities. Acquisition related costs of $0.2 million were expensed and included in the General and administrative expense line item of the consolidated statement of operations for the year ended December 31, 2018. The following table summarizes these acquisitions:

	Assets Acquired				Consideration Paid	
	Proved	Unproved	Net Working Capital	Total Fair Value	Cash	Fair Value of Common Units Issued
			(in thousands)			
March	$ 984	$ 21,452	$ 133	$ 22,569	$ 22,569	$ —
June	883	13,688	8	14,579	14,579	—
July	4,349	7,944	215	12,508	3,764	8,744
August	5,000	34,673	74	39,747	26,461	13,286
September	1,176	—	—	1,176	1,176	—
November	1,166	—	—	1,166	1,166	—
Total fair value	$ 13,558	$ 77,757	$ 430	$ 91,745	$ 69,715	$ 22,030

In addition, during 2018, the Partnership acquired mineral and royalty interests that were considered asset acquisitions from various sellers for an aggregate of $58.2 million. These acquisitions were primarily located in East Texas and the Permian Basin. The cash portion of the consideration paid for these acquisitions of $57.6 million was funded with borrowings under the Partnership's Credit Facility and funds from operating activities, and $0.6 million was funded through the issuance of common units of the Partnership based on the fair values of the common units issued on the acquisition dates.

During 2018, the Partnership acquired the remaining noncontrolling interest in certain subsidiaries for $1.7 million and merged the subsidiaries into its existing structure. This acquisition was funded with borrowings under the Partnership's Credit Facility and funds from operating activities.

Farmout Agreements

In 2017, the Partnership entered into two farmout arrangements designed to reduce its working interest capital expenditures and thereby significantly lower its capital spending other than for 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.

Canaan Farmout

In February 2017, the Partnership entered into a farmout agreement with Canaan Resource Partners ("Canaan") which covers certain Haynesville and Bossier shale acreage in San Augustine County, Texas operated by XTO Energy Inc. ("XTO"), a subsidiary of Exxon Mobil Corporation. The Partnership has an approximate 50% working interest in the acreage and is the largest mineral owner. During the first three phases of the farmout agreement, Canaan commits on a phase-by-phase basis and funds 80% of the Partnership's drilling and completion costs and is assigned 80% of the Partnership's working interests in such wells (40% working interest on an 8/8ths basis) as the wells are drilled. After the third phase, Canaan can earn 40% of the Partnership’s working interest (20% working interest on an 8/8ths basis) in additional wells drilled in the area by continuing to fund 40% of the Partnership's costs for those wells on a well-by-well basis. The Partnership receives an ORRI before payout and an increased ORRI after payout on all wells drilled under the agreement.

Canaan has participated in a total of 37 wells under the farmout agreement through December 31, 2020, covering two election phases. In 2019, XTO suspended its development activities in the area due to low natural gas prices. Canaan has the right to elect to continue its participation in a third phase covering up to 20 future wells drilled under the farmout agreement should XTO resume drilling activity.

Pivotal Farmout

In November 2017, the Partnership entered into a farmout agreement (the "First Pivotal Farmout") with Pivotal Petroleum Partners (“Pivotal”), a portfolio company of Tailwater Capital, LLC. The farmout agreement covers substantially all of the Partnership's remaining working interests in wells operated by XTO Energy and BPX Energy in the Shelby Trough area of East Texas targeting the Haynesville and Bossier shale acreage (after giving effect to the Canaan Farmout), until November 2025. Pivotal is obligated to fund the development of up to 80 wells, in designated well groups, across several development areas and then has options to continue funding the Partnership's working interest across those areas for the duration of the farmout agreement. Once Pivotal achieves a specified payout for a designated well group, the Partnership will obtain a majority of the original working interest in such well group. As of December 31, 2020, a total of 68 wells have been spud in the contract area subject to the First Pivotal Farmout. The Partnership's development agreement with BPX Energy terminated in 2019 with respect to the majority of the Partnership's acreage covered by the agreement. As such, Pivotal retains minimal rights or obligations related to the farmout for that area that remains subject to the First Pivotal Farmout.

In the second quarter of 2020, the Partnership entered into a development agreement with Aethon Energy ("Aethon") to develop certain portions of the area forfeited by BPX Energy in Angelina County, Texas. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to our mineral and leasehold acreage in the contract area. The agreement calls for a minimum of four wells to be drilled in the initial program year, which began in the third quarter of 2020, increasing to a minimum of 15 wells per year beginning with the third program year. In November 2020, the Partnership entered into a new farmout agreement (the “Second Pivotal Farmout”) with Pivotal. The Second Pivotal Farmout supersedes and replaces the First Pivotal Farmout with respect to the area covered by the Aethon development agreement. The Second 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 with 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 in accordance with the development agreement. Pivotal is 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 Second 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, 2020, a total of 2 wells have been spud in the contract area subject to the Second Pivotal Farmout.

From the inception of the farmout agreements through December 31, 2020, the Partnership has received $90.2 million and $119.2 million from Canaan and Pivotal, respectively, under the agreements. When such reimbursements are received prior to assigning the wells to Canaan and Pivotal, the Partnership records the amounts as increases to Oil and natural gas properties and Other long-term liabilities. When working interests in farmout wells are assigned to Canaan and Pivotal, the Partnership's Oil and natural gas properties and Other long-term liabilities are reduced by the reimbursed capital costs. As of December 31, 2020 and 2019, $0.1 million and $1.7 million, respectively, were included in the Other long-term liabilities line item of the consolidated balance sheets for reimbursements received associated with farmed-out working interests not yet assigned to Canaan and Pivotal.

XTO Completions Agreement

In June 2020, the Partnership entered into a new incentive agreement with XTO with respect to certain drilled but uncompleted wells ("DUCs") in the Shelby Trough. The agreement allows for royalty relief on 13 existing DUCs if XTO completes and turns the wells to sales by March 31, 2021. As of January 18, 2021, XTO has turned all 13 DUCs to sales.

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. The

Partnership recognized impairment of oil and natural gas properties of $51.0 million for the year ended December 31, 2020. No impairment of oil and natural gas properties was recognized during 2019. 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. 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, 2020, the Partnership's open derivatives contracts consisted of fixed-price-swap contracts and costless collar contracts. A fixed-price swap contract between the Partnership and the counterparty specifies a fixed commodity price and a future settlement date. A costless collar contract between the Partnership and the counterparty specifies a floor and a ceiling commodity price and a future settlement date. The Partnership has not designated any of its contracts as fair value or cash flow hedges. Accordingly, the changes in 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, 2020 and 2019. 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, 2020, the Partnership had eight counterparties, all of which are rated Baa1 or better by Moody's and are lenders under the Partnership's Credit Facility.

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

Classification	Balance Sheet Location	As of December 31, 2020 Gross Fair Value	Effect of Counterparty Netting	Net Carrying Value on Balance Sheet
		(in thousands)		
Assets:				
Current asset	Commodity derivative assets	$ 6,362	$ (5,213)	$ 1,149
Long-term asset	Deferred charges and other long-term assets	—	—	—
Total assets		$ 6,362	$ (5,213)	$ 1,149
Liabilities:				
Current liability	Commodity derivative liabilities	$ 24,531	$ (5,213)	$ 19,318
Long-term liability	Commodity derivative liabilities	1,848	—	1,848
Total liabilities		$ 26,379	$ (5,213)	$ 21,166

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

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

Derivatives not designated as hedging instruments	For the year ended December 31, 2020	2019	2018
	(in thousands)		
Beginning fair value of commodity derivative instruments	$ 15,221	$ 48,038	$ (5,028)
Gain (loss) on oil derivative instruments	36,091	(34,728)	24,300
Gain (loss) on natural gas derivative instruments	10,020	29,773	(9,469)
Net cash paid (received) on settlements of oil derivative instruments	(56,487)	(8,536)	34,905
Net cash paid (received) on settlements of natural gas derivative instruments	(24,862)	(19,326)	3,330
Net change in fair value of commodity derivative instruments	(35,238)	(32,817)	53,066
Ending fair value of commodity derivative instruments	$ (20,017)	$ 15,221	$ 48,038

The Partnership had the following open derivative contracts for oil as of December 31, 2020:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (per Bbl)	Range (per Bbl)	
			Low	High
Oil Swap Contracts:				
2020				
Fourth quarter	210,000	57.32	54.92	58.65
2021				
First quarter	660,000	38.97	32.64	46.50
Second quarter	660,000	38.97	32.64	46.50
Third quarter	660,000	38.97	32.64	46.50
Fourth quarter	660,000	38.97	32.64	46.50

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

The Partnership had the following open derivative contracts for natural gas as of December 31, 2020:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (per MMBtu)	Range (per MMBtu)	
			Low	High
Natural Gas Swap Contracts:				
2021				
First quarter	9,900,000	$ 2.69	$ 2.52	$ 3.08
Second quarter	10,010,000	2.69	2.52	3.08
Third quarter	10,120,000	2.69	2.52	3.08
Fourth quarter	10,120,000	2.69	2.52	3.08

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, 2020 and 2019.

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership estimated the fair value of 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 Counterparty	
	Level 1	**Level 2**	**Level 3**	**Netting**	**Total**
			(In thousands)		
As of December 31, 2020					
Financial Assets					
Commodity derivative instruments	$ —	$ 6,362	$ —	$ (5,213)	$ 1,149
Financial Liabilities					
Commodity derivative instruments	—	26,379	—	(5,213)	21,166
As of December 31, 2019					
Financial Assets					
Commodity derivative instruments	$ —	$ 19,741	$ —	$ (4,343)	$ 15,398
Financial Liabilities					
Commodity derivative instruments	—	4,520	—	(4,343)	177

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

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

The determination of the fair values of proved and unproved properties acquired in business combinations are estimated by discounting projected future cash flows. The factors used to determine fair value include estimates of economic reserves, future operating and development costs, future commodity prices, timing of future production, and a risk-adjusted discount rate. The Partnership has designated these measurements as Level 3. The Partnership's fair value assessments for recent acquisitions are included in Note 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, 2020				
Impaired oil and natural gas properties	$ —	$ —	$ 2,044	$ 51,031
Year Ended December 31, 2019				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —
Year Ended December 31, 2018				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —

The Partnership's estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty 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, 2020 and 2019. There were no assets measured at fair value on a non-recurring basis, after initial recognition, for the years ended 2019 and 2018.

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 20%, 18%, and 15% of total oil and natural gas revenue for the years ended December 31, 2020, 2019, and 2018, 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 and terminates on November 1, 2022. The commitment of the lenders equals the lesser of the aggregate maximum credit amount and the borrowing base. The amount of the borrowing base is redetermined semi-annually, usually in October and April, and is derived from the value of the Partnership's oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. The Partnership and the lenders (at the direction of two-thirds of the lenders) each have discretion to request a borrowing base redetermination one time between scheduled redeterminations. 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. Effective October 23, 2019, the borrowing base redetermination reduced the borrowing base to $650.0 million. Effective May 1, 2020, the borrowing base was further reduced to $460.0 million. Effective July 21, 2020, in connection with the closing of the Partnership's two asset sales in the Permian Basin, the borrowing base was further reduced to $430.0 million. Effective November 3, 2020, the most recent borrowing base redetermination reduced the borrowing base to $400.0 million. The next semi-annual redetermination is scheduled for April 2021.

Outstanding borrowings under the Credit Facility bear interest at a floating rate elected by the Partnership equal to an alternative base rate (which is equal to the greatest of the Prime Rate, the Federal Funds effective rate plus 0.50%, or 1-month LIBOR plus 1.00%) or LIBOR, in each case, plus the applicable margin. Prior to October 31, 2018, the applicable margin ranged from 1.00% to 2.00% in the case of the alternative base rate and from 2.00% to 3.00% in the case of LIBOR, depending on the borrowings outstanding in relation to the borrowing base. Effective October 31, 2018, the applicable margin for the alternative base rate was reduced to between 0.75% and 1.75% and the applicable margin for LIBOR was reduced to between 1.75% and 2.75%. Effective November 3, 2020, the LIBOR margin was increased to between 2.00% and 3.00% and the alternative base rate margin was increased to between 1.00% and 2.00%.

The weighted-average interest rate of the Credit Facility was 2.40% and 4.05% as of December 31, 2020 and 2019, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% 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. As of December 31, 2020, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $121.0 million and $394.0 million at December 31, 2020 and 2019, respectively. The unused portion of the available borrowings under the Credit Facility were $279.0 million and $256.0 million at December 31, 2020 and 2019, 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 General and administrative expense on the consolidated statements of operations. The total compensation expense related to common unit grants is measured as the number of units granted that are expected to vest 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).

Cash Awards

The Partnership may also provide from time to time short-term and long-term cash incentive and retention awards annually for its directors, executive officers, and certain other employees. Payments are disbursed as vesting is attained on a graded annual basis. The last grant of such cash awards with graded vesting requirements was made in 2016 with vestings extending through December 31, 2019.

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, net of estimated forfeitures, is recognized ratably using the straight-line attribution method.

In conjunction with the adoption of the 2015 LTIP, the Board approved a grant of awards to each of the executive officers of the Partnership's general partner, certain other employees, and each of the non-employee directors of the Partnership’s general partner. The grants included restricted common units subject to limitations on transferability, customary forfeiture provisions, and service based graded vesting requirements that extended through March 15, 2019.

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 2020 grant includes restricted common units subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through January 7, 2023. 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, 2020.

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2019	1,038,259	$ 17.67
Granted	298,279	9.97
Vested	(569,916)	17.93
Forfeited	(172,632)	17.35
Unvested at December 31, 2020	593,990	13.65

The weighted-average grant-date fair value per unit for unit-based awards was $9.97, $17.09, and $17.95 for the years ended December 31, 2020, 2019, and 2018, respectively. As of December 31, 2020, unrecognized compensation cost associated with restricted unit awards was $3.8 million, which the Partnership expects to recognize over a weighted-average period of 1.54 years. The fair value of units vested for the years ended December 31, 2020, 2019, and 2018 was $7.5 million, $12.7 million, and $12.9 million, respectively. There were no cash payments made for vested units during the years ended December 31, 2020, 2019, and 2018.

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, are probable to vest, 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 that are expected to vest are charged to partners' capital.

The following table summarizes information about performance units for the year ended December 31, 2020.

Performance units	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2019	1,369,082	$ 17.66
Granted[1]	340,036	10.95
Vested	(660,276)	17.88
Forfeited	(166,532)	17.35
Unvested at December 31, 2020	882,310	14.96

[1] Includes 41,757 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 $10.95, $16.84, and $17.94 for the years ended December 31, 2020, 2019, and 2018, respectively. Unrecognized compensation cost associated with performance unit awards was $2.0 million as of December 31, 2020, which the Partnership expects to recognize over a weighted-average period of 1.71 years. The fair value of performance units vested for the years ended December 31, 2020, 2019 and 2018 was $5.5 million, $22.7 million and $1.5 million, respectively.

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, 2020, 2019, and 2018.

Incentive compensation expense	Year Ended December 31, 2020	2019	2018
	(In thousands)		
Cash — short and long-term incentive plan	$ 2,962	$ 5,593	$ 9,301
Equity-based compensation — restricted common and subordinated units	4,688	10,751	13,624
Equity-based compensation — restricted performance units	(2,417)	7,386	14,188
Board of Directors incentive plan	1,456	2,347	2,322
Total incentive compensation expense	$ 6,689	$ 26,077	$ 39,435

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 $0.5 million, $0.7 million, and $0.7 million for the years ended December 31, 2020, 2019, and 2018, 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, 2020 will be resolved without material adverse effect on the Partnership’s financial condition or results of operations.

NOTE 12 — PREFERRED UNITS

Series A Redeemable Preferred Units

As of December 31, 2020 and 2019, there were no Series A redeemable preferred units outstanding. The Series A redeemable preferred units were entitled to an annual distribution of 10% of the outstanding funded capital of the Series A redeemable preferred units, payable on a quarterly basis in arrears.

The Series A redeemable preferred units were convertible into common and subordinated units at any time at the option of the Series A redeemable preferred unitholders. The Series A redeemable preferred units had an adjusted conversion price of $14.2683 and an adjusted conversion rate of 30.3431 common units and 39.7427 subordinated units per redeemable preferred unit.

The Series A redeemable preferred unitholders had the option to elect to have the Partnership redeem, at face value, all remaining Series A redeemable preferred units, effective as of December 31, 2017, plus any accrued and unpaid distributions.

All Series A redeemable preferred units not redeemed by March 31, 2018 automatically converted to common and subordinated units effective as of January 1, 2018 or as soon as practicable thereafter.

For the year ended December 31, 2018, 2,115 Series A redeemable preferred units were redeemed for $2.1 million, including accrued unpaid yield, and 24,248 Series A redeemable preferred units totaling $24.2 million were converted into 735,758 common units and 963,681 subordinated units as a result of the mandatory conversion subsequent to December 31, 2017.

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 an annual distribution of 7%, payable on a quarterly basis in arrears. For the eight quarters consisting of the quarter in respect of which the initial distribution is paid and the seven full quarters thereafter, the quarterly distribution may be paid, at the sole option of the Partnership, (i) in-kind in the form of additional Series B cumulative convertible preferred units (the "Series B PIK Units"), (ii) in cash, or (iii) in a combination of Series B PIK Units and cash. Beginning with the ninth quarter, all Series B cumulative convertible preferred unit distributions shall be paid in cash. The number of Series B PIK Units to be issued, if any, shall equal the quotient of the Series B cumulative convertible preferred unit distribution amount (or portion thereof) divided by the Series B cumulative convertible preferred unit purchase price of $20.3926.

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

NOTE 13 — EARNINGS PER UNIT

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

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

The Partnership assesses the Series A redeemable preferred units and 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,		
	2020	2019	2018
	(in thousands, except per unit amounts)		
NET INCOME (LOSS)	$ 121,819	$ 214,368	$ 295,560
Net (income) loss attributable to noncontrolling interests	—	—	(24)
Distributions on Series A redeemable preferred units	—	—	(25)
Distributions on Series B cumulative convertible preferred units	(21,000)	(21,000)	(21,000)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	**$ 100,819**	$ 193,368	$ 274,511
ALLOCATION OF NET INCOME (LOSS):			
General partner interest	$ —	$ —	$ —
Common units	100,819	169,375	154,662
Subordinated units	—	23,993	119,849
	$ 100,819	$ 193,368	$ 274,511
Weighted average common units outstanding:			
Weighted average common units outstanding (basic)	206,705	168,230	106,064
Effect of dilutive securities	114	146	15,200
Weighted average common units outstanding (diluted)	206,819	168,376	121,264
Weighted average subordinated units outstanding:			
Weighted average subordinated units outstanding (basic)	—	37,740	96,099
Effect of dilutive securities	—	—	247
Weighted average subordinated units outstanding (diluted)	—	37,740	96,346
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:			
Per common unit (basic)	$ 0.49	$ 1.01	$ 1.46
Per subordinated unit (basic)	—	0.64	1.25
Per common unit (diluted)[1]	0.49	1.01	1.45
Per subordinated unit (diluted)[2]	—	0.64	1.25

[1] For the year ended December 31, 2018, diluted net income (loss) attributable to common units includes distributions on Series B cumulative convertible preferred units of $21.0 million.

[2] For the year ended December 31, 2018, diluted net income (loss) attributable to subordinated units includes distributions on Series A redeemable preferred units of $0.3 million.

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

	For the Year Ended December 31,		
	2020	2019	2018
	(in thousands)		
Potentially dilutive securities (common units):			
Series A redeemable preferred units on an as-converted basis	—	—	189
Series B cumulative convertible preferred units on an as-converted basis	14,968	14,968	—
	14,968	14,968	189

NOTE 14 — COMMON AND SUBORDINATED UNITS

Common and Subordinated Units

The common units and subordinated units represent limited partner interests in the Partnership. The partnership agreement restricts unitholders' voting rights by providing that any units held by a person or group that owns 15% or more of any class of units then outstanding, other than the limited partners in Black Stone Minerals Company, L.P. prior to the 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 holders of common units are and, prior to the end of the subordination period (as defined in the Partnership agreement), the subordinated units were, entitled to participate in distributions and exercise the rights and privileges provided to limited partners holding common units and subordinated units, respectively, under the partnership agreement. The subordination period under the partnership agreement ended on the first business day after the Partnership earned and paid an aggregate amount of at least $1.35 (the annualized minimum quarterly distribution applicable for quarterly periods ending March 31, 2019 and thereafter) multiplied by the total number of outstanding common and subordinated units for a period of four consecutive, non-overlapping quarters ending on or after March 31, 2019, and there were no outstanding arrearages on the common units. This test was met upon the payment of the distribution for the first quarter of 2019. Accordingly, each outstanding subordinated unit converted into one common unit on May 24, 2019 and the priority right of the common unitholders ceased to exist.

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

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

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

	Year Ended December 31,		
	2020	2019	2018
DISTRIBUTIONS DECLARED AND PAID:			
Per common unit	$ 0.68	$ 1.48	$ 1.33
Per subordinated unit	—	0.74	1.13

Common Unit Repurchase Program

On November 5, 2018, the Board authorized the repurchase of up to $75.0 million in common units. The repurchase program authorizes the Partnership to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. The Partnership made no repurchases under this program for the year ended December 31, 2020. As of December 31, 2020, the Partnership has repurchased $4.2 million in common units under the repurchase program since inception. The repurchase program is funded from the Partnership's cash on hand or availability under the Credit Facility. Any repurchased units are canceled.

At-The-Market Offering Program

On May 26, 2017, the Partnership commenced an at-the-market offering program (the "ATM Program") and in connection therewith entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, and UBS Securities LLC, as Sales Agents (each a "Sales Agent" and collectively the "Sales Agents"). Pursuant to the terms of the ATM Program, the Partnership may sell, from time to time through the Sales Agents, the Partnership's common units representing limited partner interests having an aggregate offering amount of up to $100,000,000. Sales of common units, if any, may be made in negotiated transactions or transactions that are deemed to be "at the market" offerings as defined in Rule 415 under the Securities Act of 1933, as amended (the "Securities Act"), including sales made directly on the New York Stock Exchange or sales made to or through a market maker other than on an exchange.

Under the terms of the ATM Program, the Partnership may also sell common units to one or more of the Sales Agents as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to a Sales Agent as principal would be pursuant to the terms of a separate agreement between the Partnership and such Sales Agent.

The Partnership intends to use the net proceeds from any sales pursuant to the ATM Program, after deducting the Sales Agents' commissions and the Partnership's offering expenses, for general partnership purposes, which may include, among other things, repayment of indebtedness outstanding under the Partnership's Credit Facility.

The Equity Distribution Agreement contains customary representations, warranties and agreements, indemnification obligations, including for liabilities under the Securities Act, other obligations of the parties and termination provisions.

For the year ended December 31, 2020 and 2019, the Partnership sold no common units under the ATM Program. For the year ended December 31, 2018, the Partnership sold 2,243,775 common units under the ATM Program for net proceeds of $40.5 million.

NOTE 15 — SUBSEQUENT EVENTS

Distribution

On February 3, 2021, the Board approved a distribution for the period from October 1, 2020 to December 31, 2020 of $0.175 per common unit. Distributions were paid on February 23, 2021 to unitholders of record at the close of business on February 16, 2021.

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,		
	2020	2019	2018
		(in thousands)	
Acquisition Costs of Properties[1]:			
Proved	$ —	$ 2,288	$ 13,438
Unproved	28	41,643	136,079
Exploration Costs	—	3	13,544
Development Costs[1]	2,742	34,617	165,198
Total	$ 2,770	$ 78,551	$ 328,259

[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,	
	2020	2019
	(in thousands)	
Proved properties[1]	$ 2,220,354	$ 2,228,893
Unproved properties	937,464	1,073,447
Total	3,157,818	3,302,340
Accumulated depreciation, depletion, amortization, and impairment	(1,987,332)	(1,870,412)
Oil and natural gas properties, net	$ 1,170,486	$ 1,431,928

[1] Proved properties include capitalized costs related to farmout wells not yet assigned.

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 $39.54, $55.85, and $65.56 per barrel as of December 31, 2020, 2019, and 2018, 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 $1.99, $2.58, and $3.10 per MMBTU as of December 31, 2020, 2019, and 2018, 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 $36.43 per barrel for oil and $1.60 per Mcf for natural gas as of December 31, 2020, $52.15 per barrel for oil and $2.36 per Mcf for natural gas as of December 31, 2019, and $62.81 per barrel for oil and $2.98 per Mcf for natural gas as of December 31, 2018.

	Crude Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)
Net proved reserves at December 31, 2017	17,899	300,274	67,945
Revisions of previous estimates [1]	(35)	(11,027)	(1,873)
Purchases of minerals in place [2]	227	419	297
Extensions, discoveries and other additions [3]	4,438	95,976	20,434
Production	(4,962)	(71,622)	(16,899)
Net proved reserves at December 31, 2018	17,567	314,020	69,904
Revisions of previous estimates [1]	951	19,136	4,140
Purchases of minerals in place [2]	46	279	92
Extensions, discoveries and other additions [3]	3,263	53,158	12,123
Production	(4,777)	(77,635)	(17,716)
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
Net Proved Developed Reserves			
December 31, 2018	17,567	278,233	63,939
December 31, 2019	17,050	263,371	60,945
December 31, 2020	15,952	230,411	54,354
Net Proved Undeveloped Reserves			
December 31, 2018	—	35,787	5,965
December 31, 2019	—	45,587	7,598
December 31, 2020	—	9,800	1,633

[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 2018 and 2019 are related to well performance in certain Haynesville/ Bossier wells. 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.

[2] Includes the acquisition of mineral and royalty reserves primarily in East Texas and the Permian Basin.

[3] Includes extensions and additions related to drilling activities within multiple basins.

[4] Includes divestitures of mineral and royalty reserves primarily in the Permian 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,		
	2020	2019	2018
	(in thousands)		
Future cash inflows	$ 965,007	$ 1,619,147	$ 2,038,508
Future production costs	(99,124)	(177,550)	(222,342)
Future development costs	(59,692)	(54,132)	(58,403)
Future income tax expense	(3,019)	(5,244)	(6,333)
Future net cash flows (undiscounted)	803,172	1,382,221	1,751,430
Annual discount 10% for estimated timing	(309,675)	(534,327)	(663,814)
Total	$ 493,497	$ 847,894	$ 1,087,616

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

	Year Ended December 31,		
	2020	2019	2018
	(in thousands)		
Standardized measure, beginning of year	$ 847,894	$ 1,087,616	$ 862,649
Sales, net of production costs	(230,062)	(384,745)	(475,742)
Net changes in prices and production costs related to future production	(242,634)	(229,651)	275,091
Extensions, discoveries and improved recovery, net of future production and development costs	65,903	186,424	370,695
Previously estimated development costs incurred during the period	—	—	14,509
Revisions of estimated future development costs	(1,530)	1,198	(558)
Revisions of previous quantity estimates, net of related costs	(24,195)	51,405	(5,401)
Accretion of discount	85,109	109,158	86,441
Purchases of reserves in place, less related costs	—	1,730	8,975
Sales of reserves in place[1]	(26,795)	(3,323)	(1,137)
Changes in timing and other	19,807	28,082	(47,906)
Net increase (decrease) in standardized measures	(354,397)	(239,722)	224,967
Standardized measure, end of year	$ 493,497	$ 847,894	$ 1,087,616

[1] Due to minimal prior period divestiture activity, sales of reserves in place were previously classified as Changes in timing and other. We changed the presentation of 2019 and 2018 to be consistent with our 2020 presentation.

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.

Selected Quarterly Financial Information—Unaudited

Quarterly financial data was as follows for the periods indicated.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except for per unit data)			
2020				
Total revenue	$ 183,054	$ 38,529	$ 43,742	$ 77,426
Income (loss) from operations	80,509	(5,314)	25,228	31,686
Net income (loss)	76,112	(8,371)	23,733	30,345
Net income (loss) attributable to the general partner and common and subordinated units	70,862	(13,621)	18,483	25,095
Net income (loss) attributable to common and subordinated units per unit (basic)[1]				
Per common unit (basic)	$ 0.34	$ (0.07)	$ 0.09	$ 0.12
Per subordinated unit (basic)	$ —	$ —	$ —	$ —
Net income (loss) attributable to common and subordinated units per unit (diluted)[1]				
Per common unit (diluted)	$ 0.34	$ (0.07)	$ 0.09	$ 0.12
Per subordinated unit (diluted)	$ —	$ —	$ —	$ —
Cash distributions declared and paid per limited partner unit				
Per common unit	$ 0.3000	$ 0.0800	$ 0.1500	$ 0.1500
Per subordinated unit	—	—	—	—
Total assets	$ 1,522,567	$ 1,438,838	$ 1,260,016	$ 1,243,978
Long-term debt	388,000	323,000	147,000	121,000
Total mezzanine equity	298,361	298,361	298,361	298,361
2019				
Total revenue	$ 83,806	$ 163,618	$ 137,369	$ 103,028
Income (loss) from operations	14,594	100,666	75,233	44,679
Net income (loss)	9,017	95,087	70,247	40,017
Net income (loss) attributable to the general partner and common and subordinated units	3,767	89,837	64,997	34,767
Net income (loss) attributable to common and subordinated units per unit (basic)[1]				
Per common unit (basic)	$ 0.02	$ 0.45	$ 0.32	$ 0.17
Per subordinated unit (basic)	$ 0.02	$ 0.39	$ —	$ —
Net income (loss) attributable to common and subordinated units per unit (diluted)[1]				
Per common unit (diluted)	$ 0.02	$ 0.44	$ 0.32	$ 0.17
Per subordinated unit (diluted)	$ 0.02	$ 0.39	$ —	$ —
Cash distributions declared and paid per limited partner unit				
Per common unit	$ 0.3700	$ 0.3700	$ 0.3700	$ 0.3700
Per subordinated unit	0.3700	0.3700	—	—
Total assets	$ 1,711,887	$ 1,724,555	$ 1,595,813	$ 1,545,208
Long-term debt	435,000	436,000	413,000	394,000
Total mezzanine equity	298,361	298,361	298,361	298,361

[1] See Note 13 – Earnings Per Unit in the consolidated financial statements.

FOURTH AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT

THIS FOURTH AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT (this "Amendment") dated as of November 3, 2020, is among: BLACK STONE MINERALS COMPANY, L.P., a Delaware limited partnership, as Borrower; BLACK STONE MINERALS, L.P., a Delaware limited partnership, as Parent MLP; the Lenders party hereto; and WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent. Capitalized terms used herein but not otherwise defined herein have the meaning given such terms in the Credit Agreement.

RECITALS

Borrower, Parent MLP, Administrative Agent and Lenders are parties to that certain Fourth Amended and Restated Credit Agreement dated as of November 1, 2017, as amended by the First Amendment to Fourth Amended and Restated Credit Agreement dated as of February 7, 2018, Second Amendment to Fourth Amended and Restated Credit Agreement dated as of October 31, 2018 and Third Amendment to Fourth Amended and Restated Credit Agreement dated as of May 1, 2020 (as amended, modified or supplemented to date, the "Credit Agreement").

Section 1. Amendments to Credit Agreement.

1.1 Certain Defined Terms. The table set forth in the definition of "Applicable Margin" set forth in Section 1.02 of the Credit Agreement is hereby amended in its entirety to read as follows:

Aggregate Elected Commitment Utilization Grid					
	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Margin	2.00%	2.25%	2.50%	2.75%	3.00%
Base Rate Margin	1.00%	1.25%	1.50%	1.75%	2.00%

Section 2. Borrowing Base Reduction.

2.1 Pursuant to Section 2.08(d) of the Credit Agreement, Administrative Agent hereby notifies Borrower and Revolving Lenders that pursuant to the October 1, 2020 Scheduled Redetermination of the Borrowing Base pursuant to Section 2.08(c) of the Credit Agreement, from and after the date hereof until the next redetermination of the Borrowing Base, the amount of the Borrowing Base shall be reduced from $430,000,000 to $400,000,000.

Section 3. Miscellaneous.

3.1 Confirmation. The provisions of the Credit Agreement, as amended hereby, shall remain in full force and effect following the effectiveness hereof.

3.2 Ratification and Affirmation; Representations and Warranties. Each of Borrower and Parent MLP hereby (a) ratifies and affirms each Loan Party's obligations under, and acknowledges each Loan Party's continued liability under, each Loan Document to which such Loan Party is a party and agrees that each Loan Document to which any Loan Party is a party remains in full force and effect as expressly amended hereby and (b) represents and warrants to Administrative Agent and Lenders that as of the date hereof, after giving effect to the terms hereof:

(i) all of the representations and warranties contained in each Loan Document to which any Loan Party is a party are true and correct in all material respects (unless otherwise qualified as to materiality), except to the extent any such representations and warranties are expressly limited to an earlier date, in which case, such representations and warranties shall continue to be true and correct as of such specified earlier date,

(ii) no Default or Event of Default has occurred and is continuing, and

(iii) no event or events have occurred which individually or in the aggregate could reasonably be expected to have a Material Adverse Effect.

3.3 Counterparts. This Amendment may be executed by one or more of the parties hereto in any number of separate counterparts, and all of such counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of this Amendment by electronic transmission shall be effective as delivery of a manually executed counterpart hereof.

3.4 NO ORAL AGREEMENT. THIS AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS EXECUTED IN CONNECTION HEREWITH AND THEREWITH REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT UNWRITTEN ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

3.5 GOVERNING LAW. THIS AMENDMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF TEXAS.

3.6 Loan Document. This Amendment is a Loan Document.

[Signature pages follow]

IN WITNESS WHEREOF , the parties hereto have caused this Amendment to be duly executed as of the date first written above.

BLACK STONE MINERALS COMPANY, L.P.,
as Borrower

By: BSMC GP, L.L.C., its General Partner

By: Black Stone Mi nerals, L.P., its Sole Member
By: Black Stone Minerals GP, L.L.C.,
its General Partner

By: /s/ Jeffrey P. Wood
Name: Jeffrey P. Wood
Title: President and Chief Financial Officer

BLACK STONE MINERALS, L.P.,
as Parent MLP

By: Black Stone Minerals GP, L.L.C.,
its General Partner

By: /s/ Jeffrey P. Wood
Name: Jeffrey P. Wood
Title: President and Chief Financial Officer

Exhibit 21.1

SUBSIDIARIES OF BLACK STONE MINERALS, L.P.

Entity	Jurisdiction of Organization
Black Stone Energy Company, L.L.C.	Texas
Black Stone Energy Company, L.L.C. of TX	Texas
Black Stone Louisiana L.L.C.	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
TLW Investments, L.L.C.	Oklahoma
NAMP Holdings, L.L.C.	Delaware
NAMP GP, L.L.C.	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. 333-203909) pertaining to the Long-Term Incentive Plan of Black Stone Minerals, L.P.,

(2) Registration Statement (Form S-3 No. 333-231630) of Black Stone Minerals, L.P., and

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

of our reports dated February 23, 2021, 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) for the year ended December 31, 2020.

/s/ Ernst & Young LLP

Houston, Texas
February 23, 2021

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use of the name Netherland, Sewell & Associates, Inc., the references to our report of Black Stone Minerals, L.P.'s proved oil and natural gas reserves estimates and future net revenue as of December 31, 2020, and the inclusion of our corresponding report letter, dated January 20, 2021, in the 2020 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. 333-203909), Form S-3 (No. 333-211426), and Form S-3 (No. 333-215857) of Black Stone Minerals, L.P.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Senior Vice President

Houston, Texas
February 23, 2021

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 23, 2021

/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 23, 2021

/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 23, 2021

/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 23, 2021

/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 20, 2021

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, 2020, 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, 2020, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	15,893.4	218,434.1	773,108.2	475,070.1
Proved Developed Non-Producing	58.7	11,977.5	18,805.9	10,709.0
Proved Undeveloped	—	9,799.6	14,277.4	9,518.9
Total Proved	15,952.1	240,211.2	806,191.4	495,297.9

Totals may not add because of rounding.

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

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

Gross revenue is Black Stone's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Black Stone's share of production taxes, ad valorem taxes,

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info@nsai-petro.com
netherlandsewell.com

capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2020. For oil volumes, the average West Texas Intermediate spot price of $39.54 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $1.985 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 $36.43 per barrel of oil and $1.598 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 workovers, 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 logs, 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

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E. 102425
Senior Vice President

Date Signed: January 20, 2021

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:

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

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

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

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

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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

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.

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

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(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.