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

FORM 10-K

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

For the fiscal year ended December 31, 2018

OR

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

For the transition period _______________ to _______________

Commission file number 001-37362

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

Delaware	**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)**

Registrant's telephone number, including area code: (713) 445-3200

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

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 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 $1,501,371,840 on June 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter, based on a closing price of $18.49 per unit as reported by the New York Stock Exchange on such date. As of February 19, 2019, 108,851,353 common units, 96,328,836 subordinated units, and 14,711,219 Series B cumulative convertible preferred units of the registrant were outstanding.

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

BLACK STONE MINERALS, L.P.
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GLOSSARY OF TERMS

The following list includes a description of the meanings of some of the oil and gas industry terms used in this Annual Report on Form 10-K ("Annual Report").

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.

GLOSSARY OF TERMS

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.

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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.

PDP. Proved developed producing, used to characterize reserves.

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.

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.

PUD. Proved undeveloped, used to characterize reserves.

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. 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. 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.

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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. 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.

Trend. A region of oil and/or natural gas production, the geographic limits of which have been generally defined, having geological characteristics that have been ascertained through supporting geological, geophysical, or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

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.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report may constitute “forward-looking statements.” The words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “should,” “would,” “could,” or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those summarized below:

- our ability to execute our business strategies;
- the volatility of realized oil and natural gas prices;
- the level of production on our properties;
- the overall supply and demand for oil and natural gas, and regional supply and demand factors, delays, or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- our ability to identify, complete, and integrate acquisitions;
- general economic, business, or industry conditions;
- competition in the oil and natural gas industry;
- 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.

Unless the context clearly indicates otherwise, references in this Annual Report on Form 10-K to "BSMC," "Black Stone Minerals, L.P. Predecessor," or "our predecessor," refer to Black Stone Minerals Company, L.P. and its subsidiaries for time periods prior to the initial public offering of Black Stone Minerals, L.P. on May 6, 2015 (the "IPO"), and references to "BSM," "Black Stone," "we," "our," "us," "the Partnership," or like terms refer to Black Stone Minerals, L.P. and its subsidiaries for time periods subsequent to the IPO.

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. 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. Our primary business objective is to grow our reserves, production, and cash generated from operations over the long term, while paying, to the extent practicable, a growing quarterly distribution to our unitholders.

We own mineral interests in approximately 16.8 million acres, with an average 43% ownership interest in that acreage. We also own NPRIs in 1.9 million acres and ORRIs in 2.1 million acres. These non-cost-bearing interests, which we refer to collectively as our "mineral and royalty interests," include ownership in over 60,000 producing wells. Our mineral and royalty interests are located in 41 states in the continental United States, 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.

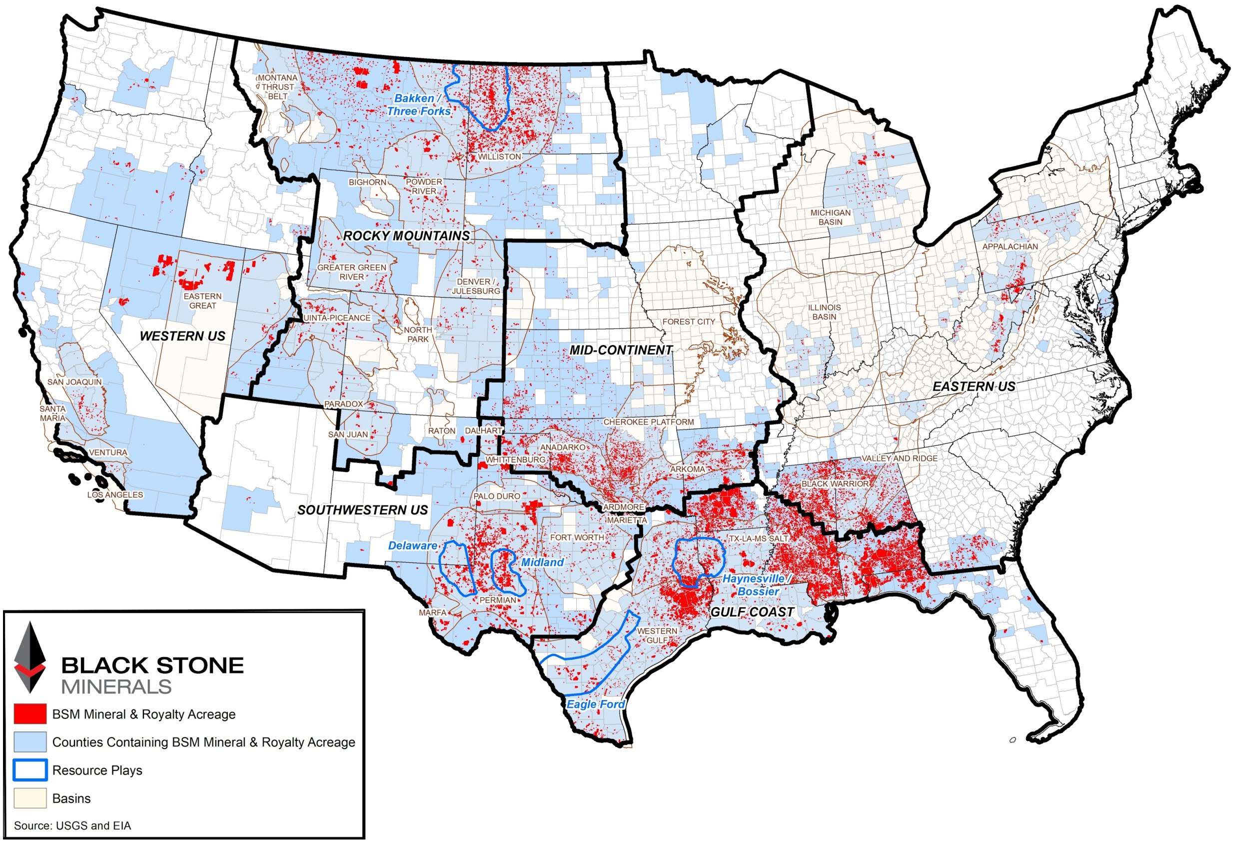
We are a publicly traded Delaware limited partnership formed on September 16, 2014. On May 6, 2015, we completed our initial public offering of 22,500,000 common units representing limited partner interests. Our common units trade on the New York Stock Exchange under the symbol "BSM."

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, 2018, our total estimated proved oil and natural gas reserves were 69,904 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, 2018, approximately 91.5% were proved developed reserves (approximately 85.7% proved developed producing and 5.8% proved developed non-producing) and approximately 8.5% were proved undeveloped reserves. At December 31, 2018, our estimated proved reserves were 25% oil and 75% 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 mineral royalty, 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 production or drilling 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, 2018, approximately 28% of our mineral and royalty interests are leased, calculated on a cumulative gross acreage basis for all three types of mineral and royalty interests. We have relied on representations made in the relevant purchase agreements to determine leasing status of recently acquired acreage.

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., a subsidiary of Exxon Mobil Corporation, and our other major operator in the area. 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 have significantly reduced the number of wells in which we participate with a working interest. We generally farmout or sell these participation rights to third parties and often retain some form of non-cost-bearing interest in those wells, such as an overriding royalty interest.

When we participate in non-operated working interest opportunities, we are required to pay our portion of the costs associated with drilling and operating these wells. Working interest production represented 31% of our total production volumes during the year ended December 31, 2018. As of December 31, 2018, we owned non-operated working interests in 9,919 gross (354 net) wells.

Our 2019 capital expenditure budget associated with our non-operated working interests is expected to be approximately$10.0 million. The majority of this capital will be spent for workovers on existing wells in which we own a working interest, or for acquiring new leasehold acreage for subsequent farmout (discussed below) in the Haynesville/Bossier play.

Farmout Agreements

On February 21, 2017, we announced that we entered into a farmout agreement with Canaan Resource Partners ("Canaan", and such farmout, the "Canaan Farmout"), which covers certain Haynesville and Bossier shale acreage in San Augustine County, Texas operated by XTO Energy Inc. We have an approximate 50% working interest in the acreage. A total of 18 wells were drilled over an initial phase, beginning with wells spud after January 1, 2017. Canaan has elected to participate in an additional phase for the lesser of 2 years or until 20 wells have been drilled. After the completion of the second phase, Canaan will have the option to elect for a similar third phase. During the first three phases of the 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 will receive a base ORRI before payout and an additional ORRI after payout on all wells drilled under the agreement. From the inception of the agreement through December 31, 2018, we have received $80.7 million from Canaan under the agreement and assigned to Canaan working interests in certain wells that have been drilled and completed.

On November 21, 2017, we entered into a farmout agreement 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. In wells operated by XTO Energy Inc. in San Augustine County, Texas, Pivotal will earn our remaining working interest not covered by the Canaan Farmout (10% working interest on an 8/8ths basis), as well as 100% of our working interests (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells operated by our other major operator in San Augustine and Angelina counties, Texas. Initially, Pivotal is obligated to fund the development of up to 80 wells across several development areas and then has options to continue funding our working interest across those areas for the duration of the farmout agreement. Pivotal will fund designated groups of wells. 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. From the inception of the agreement through December 31, 2018, we have received $63.0 million from Pivotal under the agreement and assigned to Pivotal working interests in certain wells drilled and completed.

As a result of the farmout agreements with Canaan and Pivotal, we expect net capital requirements associated with non-operated working interests to be minimal in 2019.

PepperJack Prospect

We have cumulatively spent approximately $13.1 million to drill two wells within our PepperJack prospect in Hardin and Liberty counties, Texas. The PepperJack A#1 well targeting the Lower Wilcox formation was drilled during the fourth quarter of 2017 and the first quarter of 2018. The PepperJack B#1 well, also targeting the Lower Wilcox formation, was drilled during the second quarter of 2018 to further delineate the prospect.

Based on the log results, we believe the PepperJack A#1 well is highly prospective and will be completed as a commercially productive well. The PepperJack B#1 well, which was a significant step-out from the PepperJack A#1 well, is not likely to be completed in the near term. Accordingly, we have recorded $6.8 million of costs for the PepperJack B#1 well to the Exploration expense line item of the consolidated statements of operations for the year ended December 31, 2018.

On September 21, 2018, we entered into an exploration agreement with a consortium of private exploration and production companies (the “Development Partners”) to further delineate and develop the PepperJack prospect. As part of the agreement, we assigned 75% of our working interest in the PepperJack A#1 well and acreage in the associated unit to the Development Partners and transferred our status as the operator of record. We received proceeds of $6.4 million for the assignment, which represented a reimbursement for 100% of the drilling costs and associated acreage, proceeds of $1.0 million for an option covering our mineral interests and leases in the PepperJack prospect area, and an overriding royalty interest in the PepperJack prospect area. The Development Partners began completion operations on the PepperJack A#1 well in the fourth quarter of 2018, and we are participating as a 25% non-operated working interest owner.

Our Properties

BSM Land Regions

We divide the contiguous United States into major geographical regions that we refer to as "BSM Land Regions". The following is 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 US.*** The Southwestern US region consists of the land area north of the US-Mexico border from north-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 US.*** The Eastern US region consists of the land area east of the Mississippi River and north of the Gulf Coast region. This region includes the 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 US.*** The Western US region consists of the land area west of the Rocky Mountains and Southwestern US 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, 2018[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	7,870,800	52.3%	615,430	3.6%	406,073	3.8%	432,483	96,033
Southwestern US	2,856,033	24.9%	1,006,317	2.4%	213,637	1.8%	60,879	17,630
Rocky Mountains	2,144,803	15.3%	244,839	3.4%	1,026,455	2.6%	97,932	16,720
Eastern US	1,657,834	47.4%	1,727	4.0%	74,892	1.4%	13,487	1,346
Mid-Continent	1,292,995	34.2%	39,483	3.9%	349,046	3.3%	40,622	23,860
Western US	1,025,167	89.1%	333	1.8%	30,810	3.1%	—	—
Total	16,847,632	43.3%	1,908,129	3.0%	2,100,913	2.8%	645,403	155,589

[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, while overlap between the different types of mineral and royalty interests is not significant.

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

[3] Reflects 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 mineral royalty for all of our mineral interests is approximately 20%, which may be multiplied by our ownership interest to approximate the average royalty interest in our mineral interests.

[4] Reflects 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, 2018[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	2018	2017	2016	2018	2017	2016
Gulf Coast	11,702	2,307	16,425	13,016	11,235	11,869	10,056	7,428
Southwestern US	26,336	1,149	5,081	2,966	1,493	278	426	442
Rocky Mountains	12,442	2,044	7,050	4,440	4,018	934	1,157	1,714
Eastern US	1,988	256	886	1,027	995	22	24	25
Mid-Continent	7,960	4,162	2,366	2,343	2,602	1,120	1,287	1,456
Western US	831	1	270	269	275	—	—	—
Total	61,259	9,919	32,078	24,061	20,618	14,223	12,950	11,065

[1] We own both mineral and royalty interests and working interests in 4,192 of the wells shown in each column above.

[2] Refers to mineral and royalty interest wells.

Material Resource Plays

The following is an overview of the resource plays we consider most material to our current and future business. These plays accounted for 70% of our aggregate production for the year ended December 31, 2018.

- ***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 United States, 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 United States. 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 US 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 US 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. We are experiencing a significant level of development drilling on our mineral interests within the oil and rich-gas and condensate areas of the play.

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, 2018[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	399,691	16.9%	39,744	1.3%	15,450	1.3%	55,480	7,300
Haynesville/Bossier	393,744	62.0%	28,442	1.6%	29,488	4.8%	231,269	53,994
Permian-Midland	291,770	5.7%	146,786	0.6%	107,996	0.6%	160	4
Permian-Delaware	132,897	10.5%	37,301	0.7%	6,643	2.4%	2,522	1,171
Eagle Ford	67,447	14.2%	106,729	1.2%	49,572	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, while overlap between the different types of mineral and royalty interests is not significant.

2 Excludes acreage for which we have incomplete seller records.

3 Reflects 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 mineral royalty for all of our mineral interests is approximately 20%, which may be multiplied by our ownership interest to approximate the average royalty interest in our mineral interests.

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

	Mineral and Royalty Interests					Working Interests		
	Gross Well Count as of December 31, 2018[1]		Average Daily Production (Boe/d) for the Year Ended December 31,			Average Daily Production (Boe/d) for the Year Ended December 31,		
Resource Play	**MRI Wells[2]**	**WI Wells**	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Bakken/ Three Forks	3,322	513	5,007	2,769	2,789	693	812	1,359
Haynesville/Bossier	1,013	326	10,273	5,943	4,962	10,657	10,972	5,439
Permian-Midland	1,287	2	1,792	717	150	1	—	1
Permian-Delaware	375	20	2,207	791	443	65	157	150
Eagle Ford	797	27	1,920	1,768	2,210	12	16	76

[1] We own both mineral and royalty interests and working interests in 840 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, 2018, 2017, and 2016 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. J. Carter Henson, Jr. Mr. Henson, a Licensed Professional Engineer in the State of Texas (License No. 73964), has been practicing consulting petroleum engineering at NSAI since 1989 and has over 8 years of prior industry experience. He graduated from Rice University in 1981 with Bachelor of Science Degree in Mechanical Engineering. As technical principal, Mr. Henson 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, 2018 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. Brock Morris, our Senior Vice President, Engineering and Geology, is primarily responsible for overseeing the preparation of all of our reserve estimates. Mr. Morris is a petroleum engineer with approximately 33 years of reservoir-engineering and operations experience.

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

- Comparison of historical operating expenses from the lease operating statements to the operating costs input in the reserves database;
- Review of working interests, net revenue interests, and royalty interests in the reserves database against our well ownership system;

- Review of historical realized commodity prices and differentials from index prices compared to the differentials used in the reserves database;
- Evaluation of capital cost assumptions derived from Authority for Expenditure estimates received;
- Review of actual historical production volumes compared to projections in the reserve report;
- Discussion of material reserve variances among our internal reservoir engineers and our Senior Vice President, Engineering and Geology; and
- Review of preliminary reserve estimates by our President and Chief Executive Officer 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, 2018, 2017, and 2016 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

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,		
	2018[1]	2017[2]	2016[3]
		(Unaudited)	
Estimated proved developed reserves[4]:			
Oil (MBbls)	17,567	17,891	18,150
Natural gas (MMcf)	278,233	233,017	223,057
Total (MBoe)	63,939	56,727	55,327
Estimated proved undeveloped reserves[5]:			
Oil (MBbls)	—	8	218
Natural gas (MMcf)	35,787	67,257	47,282
Total (MBoe)	5,965	11,218	8,098
Estimated proved reserves:			
Oil (MBbls)	17,567	17,899	18,368
Natural gas (MMcf)	314,020	300,274	270,339
Total (MBoe)	69,904	67,945	63,425
Percent proved developed	91.5%	83.5%	87.2%

1 Estimates of reserves as of December 31, 2018, were 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 in the period from January through December 2018. For oil volumes, the average WTI spot oil price of $65.56 per barrel is used for estimates of reserves for all the properties as of December 31, 2018. This average price is adjusted for quality, transportation fees, and market differentials. For natural gas volumes, the average Henry Hub price of $3.10 per MMBTU is used for estimates of reserves for all the properties as of December 31, 2018. This average price is 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 are $62.81 per barrel for oil and $2.98 per Mcf for natural gas.

2 Estimates of reserves as of December 31, 2017 were 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 in the period January through December 2017. For oil volumes, the average WTI spot oil price of $51.34 per barrel is used for estimates of reserves for all the properties as of December 31, 2017. These average prices are adjusted for quality, transportation fees, and market differentials. For natural gas volumes, the average Henry Hub price of $2.98 per MMBTU is used for estimates of reserves for all the properties as of December 31, 2017. 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 are $46.59 per barrel for oil and $2.70 per Mcf for natural gas.

3 Estimates of reserves as of December 31, 2016 were 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 in the period January through December 2016. For oil volumes, the average WTI spot oil price of $42.75 per barrel is used for estimates of reserves for all the properties as of December 31, 2016. These average prices are adjusted for quality, transportation fees, and market differentials. For natural gas volumes, the average Henry Hub price of $2.48 per MMBTU is used for estimates of reserves for all the properties as of December 31, 2016. 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 are $37.50 per barrel for oil and $2.14 per Mcf for natural gas.

4 As of December 31, 2018, no proved developed reserves were attributable to noncontrolling interests in our consolidated subsidiaries. Proved developed reserves of 61 and 74 MBoe were attributable to noncontrolling interests in our consolidated subsidiaries as of December 31, 2017 and 2016, respectively.

[5] As of December 31, 2018, 2017, and 2016, no proved undeveloped reserves were attributable to noncontrolling interests in our consolidated subsidiaries.

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, 2018, which is included as an exhibit to this Annual Report.

Estimated Proved Undeveloped Reserves

As of December 31, 2018, our PUDs comprised 35,787 MMcf of natural gas, for a total of 5,965 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following tables summarizes our changes in PUDs during the year ended December 31, 2018 (in MBoe):

	Estimated Proved Undeveloped Reserves (Unaudited)
As of December 31, 2017	11,218
Acquisitions of reserves	—
Divestiture of reserves	—
Extensions and discoveries	5,965
Revisions of previous estimates	(1,725)
Transfers to estimated proved developed	(9,493)
As of December 31, 2018	5,965

New PUD reserves totaling 5,965 MBoe were added during the year ended December 31, 2018, resulting from development activities in the Haynesville/Bossier play. In 2018 we did not acquire or divest any PUD reserves.

During the year ended December 31, 2018, we had reductions of 1,725 MBoe of PUD reserves, primarily as a result of the plugging and abandonment of two wells due to mechanical issues and converted the remaining 9,493 MBoe of PUD reserves to PDP reserves.

During the year ended December 31, 2018, we incurred $8.6 million relating to the development of locations that were classified as PUDs as of December 31, 2017. Additionally, during the year ended December 31, 2018, we incurred $13.1 million drilling and completing other wells that were not classified as PUDs as of December 31, 2017. There are no estimated future development costs projected for the development of PUD reserves as of December 31, 2018. All our PUD drilling locations as of December 31, 2018 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 authorization for expenditure and which remained undrilled as of December 31, 2018. As of December 31, 2018, approximately 8.5% 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, 2018, 29.4% of our production and 55.6% 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 70.6% of our production and 44.4% 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,		
	2018	2017	2016
Production:			
Oil and condensate (MBbls)[1]	4,962	3,552	3,680
Natural gas (MMcf)[1]	71,622	59,779	47,498
Total (MBoe)	16,899	13,515	11,596
Average daily production (MBoe/d)	46.3	37.0	31.7
Realized Prices[2]:			
Oil and condensate (per Bbl)	$ 62.53	$ 47.78	$ 38.69
Natural gas and natural gas liquids (per Mcf)[1]	$ 3.47	$ 3.19	$ 2.59
Unit Cost per Boe:			
Production costs and ad valorem taxes	$ 3.81	$ 3.51	$ 3.06

1 As a mineral and royalty interest owner, we are often provided insufficient and inconsistent data by our operators related to NGLs. As a result, we are unable to reliably determine the total volumes of NGLs associated with the production of natural gas on our acreage. As such, the realized prices for natural gas account for all value attributable to NGLs. The oil and condensate production volumes and natural gas production volumes do not include NGL volumes.

2 Excludes the effect of commodity derivative instruments.

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, 2018[1]		
	Mineral and Royalty Interests	Working Interests	
Well Type	**Gross**	**Gross**	**Net**
Oil	41,557	3,909	65
Natural Gas	19,702	6,010	289
Total	61,259	9,919	354

1 We own both mineral and royalty interests and working interests in 4,192 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, 2018:

BSM Land Region	Developed Acreage[1]	Undeveloped Acreage[1]	Total Acreage[1]
Gulf Coast	744,647	8,147,656	8,892,303
Southwestern US	1,043,364	3,032,623	4,075,987
Rocky Mountains	928,972	2,487,125	3,416,097
Eastern US	82,072	1,652,381	1,734,453
Mid-Continent	656,770	1,024,754	1,681,524
Western US	17,489	1,038,821	1,056,310
Total	3,473,314	17,383,360	20,856,674

[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, while 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, 2018:

	Developed Acreage[1]		Undeveloped Acreage[1]		Total Acreage[1]	
BSM Land Region	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	218,353	36,717	214,130	59,316	432,483	96,033
Southwestern US	15,910	11,632	44,969	5,998	60,879	17,630
Rocky Mountains	85,384	15,411	12,548	1,309	97,932	16,720
Eastern US	13,408	1,346	79	—	13,487	1,346
Mid-Continent	39,636	23,840	986	20	40,622	23,860
Western US	—	—	—	—	—	—
Total	372,691	88,946	272,712	66,643	645,403	155,589

[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, while 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, 2019, 2020, and 2021, and, where applicable, the net acres expiring that are subject to extension options:

	2019 Expirations		2020 Expirations		2021 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.**
66,643	3,184	501	3,829	1,234	3,267	311

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. 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,		
	2018	**2017**	**2016**
Gross development wells:			
Productive	6.0	23.0	47.0
Dry	—	—	—
Total	6.0	23.0	47.0
Net development wells:			
Productive	2.5	6.1	4.7
Dry	—	—	—
Total	2.5	6.1	4.7
Gross exploratory wells:			
Productive	—	—	—
Dry	1.0	—	—
Total	1.0	—	—
Net exploratory wells:			
Productive	—	—	—
Dry	1.0	—	—
Total	1.0	—	—

For the years ended December 31, 2017 and 2016 we did not have any productive or dry exploratory wells on a gross or net basis. As of December 31, 2018, we had one gross well in the process of drilling, completing or dewatering, or shut in awaiting infrastructure that is not reflected in the above table.

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 often require compliance measures 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. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. Pursuant to the consent decree, EPA must complete any revisions to RCRA's Subtitle D regulations by 2021. Removal of RCRA's exemption for exploration and production wastes has the potential to significantly increase waste disposal costs, which in turn will result in increased operating costs and could adversely impact production on our properties. Administrative, civil, and criminal penalties can be imposed for failure to comply with 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"). Several legal challenges to the rule followed, along with attempts to stay implementation following the change in presidential administration. Currently, the WOTUS rule is active in 26 states and enjoined in 24 states. Future implementation of the June 2015 rule is uncertain at this time. To the extent this rule or a revised rule expands the scope of the CWA’s jurisdiction, operations on our properties could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas in connection with any expansion activities. 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, while the SDWA, generally excludes hydraulic fracturing from the definition of underground injection, it does not exclude hydraulic fracturing involving the use of diesel fuels. In 2014, the EPA published draft permitting guidance governing hydraulic fracturing with diesel fuels. 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. Moreover, the SDWA also regulates saltwater disposal wells under the Underground Injection Control 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 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 August 2012, the EPA adopted new regulations under the Clean Air Act that established new emission control requirements for oil and natural gas production and processing operations. In addition, 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

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established on a case-by-case basis. These EPA rulemakings could adversely affect operations on our properties and restrict or delay the ability of our operators to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include gathering and boosting facilities as well as GHG emissions from completions and workovers of hydraulically fractured wells. Also, in June 2016, the EPA finalized rules that establish new air emission controls for methane emissions from certain new, modified, or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission, and storage activities, otherwise known as Subpart OOOOa. Following the change in administration, there have been attempts to modify these regulations, and litigation is ongoing. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements with any certainty. Several states, including Colorado, where we hold interests, have also adopted rules to control and minimize methane emissions from the production of oil and natural gas. Moreover, in response to public concerns regarding methane emissions, many operators have recently voluntarily agreed to implement methane controls with respect to their operations. State and existing federal methane rules have substantial similarities with respect to pollution control equipment and leak detection and repair ("LDAR") requirements. These rules could result in increased compliance costs for operations on our properties and require compliance expenditures to purchase pollution control equipment and hire additional personnel to assist with complying with LDAR requirements, such as increased frequency of inspections and repairs for certain processes and equipment. Consequently, these and other regulations related to controlling GHG emissions could have an adverse impact on production on our properties, our business, and results of operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation, a number of state and regional GHG cap and trade programs have emerged. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our operators' equipment and operations could require them to incur costs to reduce emissions of GHGs associated with their operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas produced from our properties and lower the value of our reserves. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states, as well as state and local climate change initiatives, could adversely affect the oil and natural gas industry, and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult for operators on our properties to secure funding for exploration and production activities. Additionally, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or restrict more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult for operators to engage in exploration and production activities.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Exploration and production activities are capital intensive, and capital constraints of our operators could have a material adverse impact on production from our properties. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events; if any of these effects were to occur, they could have a material adverse effect on our properties and operations.

Hydraulic Fracturing

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 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 some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals, or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. 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, in Texas, the Texas Railroad Commission ("RRC") published a final rule in October 2014 governing permitting or re-permitting of disposal wells that requires, 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, from time to time in Colorado there have been various ballot initiatives to impose strict setback requirements on oil and gas activities from certain occupied structures and environmental sensitive areas, which could have potentially prohibited future production in areas in which we own interests. 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 revenues for the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
XTO Energy Inc.	15.4%	20.8%	11.0%

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.

Employees

We are managed and operated by the board of directors and executive officers of our general partner. All of our employees, including our executive officers, are employees of Black Stone Natural Resources Management Company (“Black Stone Management”). As of December 31, 2018, Black Stone Management had 116 full-time employees. None of Black Stone Management’s employees are represented by labor unions or covered by any collective bargaining agreements.

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.

Risks Related to Our Business

We may not generate sufficient cash from operations after establishment of cash reserves to pay the minimum quarterly distribution on our common and subordinated 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 and subordinated 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 the full minimum quarterly distribution to our common and subordinated unitholders. Our Series B cumulative convertible preferred unitholders have priority with respect to rights to share in distributions over our common and subordinated 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 and subordinated unitholders on a quarterly basis or otherwise. The amount of cash to be distributed each quarter will be determined by the board of directors of our general partner.

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 replacement capital expenditures, acquisitions, and participation in working interests. If over the long term we do not retain cash for replacement 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 will 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.

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, 2018		During the Five Years Prior to 2019		As of December 31,		
	High	Low	High[2]	Low[3]	2018	2017	2016
WTI spot crude oil ($/Bbl)[1]	$ 77.41	$ 44.48	$ 107.95	$ 26.19	$ 45.15	$ 60.46	$ 53.75
Henry Hub spot natural gas ($/MMBtu)[1]	$ 6.24	$ 2.49	$ 8.15	$ 1.49	$ 3.25	$ 3.69	$ 3.71

[1] Source: EIA
[2] High prices for WTI and Henry Hub were in 2014
[3] Low prices for WTI and Henry Hub were in 2016

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.

For the foreseeable future, oil prices are expected to trade in a lower range compared to recent historical highs. Approximately 56% of our 2018 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 the minimum quarterly distribution on all our outstanding common and subordinated units, perhaps materially.

The spot WTI market price at Cushing, Oklahoma has declined from $98.17 per Bbl on December 31, 2013 to $45.15 per Bbl on December 31, 2018. 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 bank credit facility and reduce the amounts of cash we would otherwise have available to pay expenses, fund capital expenditures, make distributions to our unitholders, and service our indebtedness.

For the forseeable future, natural gas prices are expected to trade in a range lower than historical highs. Approximately 44% of our 2018 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 the minimum quarterly distribution on all our outstanding common and subordinated units, perhaps materially.

During the ten years prior to 2018, natural gas prices at Henry Hub have ranged from a high of $13.31 per MMBtu in 2008 to a low of $1.49 per MMBtu in 2016. On December 31, 2018, the Henry Hub spot market price of natural gas was $3.25 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, 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 bank 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.

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.

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, 2018, 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.

If operators slow or cease activity in the Shelby Trough area, our results of operations could be adversely affected.

In 2018, we generated 21.4% of our revenues and 36.7% of our production 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; we expect that these operators will continue to conduct significant operations in this area for the foreseeable future in accordance with contractual arrangements. 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

If any of these risks are realized and production is not replaced by another operator in this area or another area, production may decrease, reducing cash generated from operations and cash available for distribution.

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

A failure on the part of the operators to make royalty payments gives us the right to terminate the lease, repossess the property, and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement operator. However, we might not be able to find a replacement operator and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to a proceeding under title 11 of the United States Code (the “Bankruptcy Code”), in which case our right to enforce or terminate the lease for any defaults, including non-payment, may be substantially delayed or otherwise impaired. In general, in a proceeding under the Bankruptcy Code, the bankrupt operator would have a substantial period of time to decide whether to ultimately reject or assume the lease, which could prevent the execution of a new lease or the assignment of the existing lease to another operator. In the event that the operator rejected the lease, our ability to collect amounts owed would be substantially delayed, and our ultimate recovery may be only a fraction of the amount owed or nothing. In addition, if we are able to enter into a new lease with a new operator, the replacement operator may not achieve the same levels of production or sell oil or natural gas at the same price as the operator it replaced.

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 make and expect to continue to make substantial capital expenditures in connection with the acquisition of mineral and royalty interests and 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.

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 and subordinated 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 current reserves. The production decline rates of our properties may be significantly higher than currently 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 and subordinated 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.

Our operators' identified potential drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

The ability of our operators to drill and develop identified potential drilling locations depends on a number of uncertainties, including the availability of capital, construction of infrastructure, inclement weather, regulatory changes and approvals, oil and natural gas prices, costs, drilling results, and the availability of water. Further, our operators' identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. The use of technologies and the study of producing fields in the same area will not enable our operators to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, our operators may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If our operators drill additional wells that they identify as dry holes in current and future drilling locations, their drilling success rate may decline and materially harm their business as well as ours.

We cannot assure you that the analogies our operators draw from available data from the wells on our acreage, more fully explored locations, or producing fields will be applicable to their drilling locations. Further, initial production rates reported by our or other operators in the areas in which our reserves are located may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations our operators have identified will ever be drilled or if our operators will be able to produce oil or natural gas from these or any other potential drilling locations. As such, the actual drilling activities of our operators may materially differ from those presently identified, which could adversely affect our business, results of operation, and cash distributions to unitholders.

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 (particularly sand and other proppants), 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 (particularly sand and other proppants), 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, 2018, 2017, and 2016 were prepared by NSAI, a third-party petroleum engineering firm, which conducted a detailed review of all 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, 2018, 2017, and 2016 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, 2018, 2017, and 2016, 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.

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.

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. 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.

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. When drilling horizontal wells, operators risk not landing the well bore in the desired drilling zone and straying from the desired drilling zone. When drilling horizontally through a formation, operators risk being unable to run casing through the entire length of the well bore and being unable to run tools and other equipment consistently through the horizontal well bore. Risks that our operators face while completing wells include being unable to fracture stimulate the planned number of stages, to run tools the entire length of the well bore during completion operations, and to clean out the well bore after completion of the final fracture stimulation stage. 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.

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

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

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

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

Additionally, federal and state regulatory authorities may expand or alter applicable pipeline-safety laws and regulations, compliance with 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. The EPA however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program and issued permitting guidance in February 2014 applicable to hydraulic fracturing involving the use of diesel fuel. The EPA has also issued effluent limitation guidelines in June 2016 to 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” associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals, or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. 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 Texas Railroad Commission ("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, from time to time in Colorado there have been various ballot initiatives to impose strict setback requirements on oil and gas activities from certain occupied structures and environmental sensitive areas, which could have potentially prohibited future production in areas in which we own interests. 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.

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, 2018, we had outstanding borrowings of $410.0 million and the aggregate maximum credit amounts of the lenders were $1.0 billion. Our borrowing base determined by the lenders under our credit facility in October 2018 is $675.0 million and the next semi-annual redetermination is scheduled for April 2019. 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.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas that our operators produce.

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established on a case-by-case basis. These EPA rulemakings could adversely affect operations on our properties and restrict or delay the ability of our operators to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include gathering and boosting facilities as well as GHG emissions from completions and workovers of hydraulically fractured wells. Also, in June 2016, the EPA finalized rules that establish new air emission controls for methane emissions from certain new, modified, or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission, and storage activities, otherwise known as Subpart OOOOa. Following the change in administration, there have been attempts to modify these regulations, and litigation is ongoing. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements with any certainty. Several states, including Colorado, where we hold interests, have also adopted rules to control and minimize methane emissions from the production of oil and natural gas. Moreover, in response to public concerns regarding methane emissions, many operators have recently voluntarily agreed to implement methane controls with respect to their operations. State and federal methane rules have substantial similarities with respect to pollution control equipment and leak detection and repair ("LDAR") requirements. These rules could result in increased compliance costs for our operators and require them to make expenditures to purchase pollution control equipment and hire additional personnel to assist with complying with LDAR requirements, such as increased frequency of inspections and repairs for certain processes and equipment. Consequently, these and other regulations related to controlling GHG emissions could have an adverse impact on production on our properties, our business and results of operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation, a number of state and regional cap and trade programs have emerged. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our operators' equipment and operations could require them to incur costs to reduce emissions of GHGs associated with their operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas produced from our properties and lower the value of our reserves. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states, as well as state and local climate change initiatives, could adversely affect the oil and natural gas industry, and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business. Moreover, activists concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult for operators on our properties to secure funding for exploration and production activities. Additionally, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or restrict more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult for operators to engage in exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Exploration and production activities are capital intensive, and capital constraints of our operators could have a material adverse impact on production from our properties. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events; if any of these effects were to occur, they could have a material adverse effect on our properties and operations.

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.

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.

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

Various securities 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, delays in production or delivery, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, material adverse effects on our reputation or financial position and other operational disruptions and third-party liabilities, including the cost of remedial actions. Cyber attacks and data breaches in particular are becoming more sophisticated and include, but are not limited to, malicious software, ransomware, attempts to gain unauthorized access to data, employee and third-party errors, and other electronic security breaches. 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.

Risks Inherent in an Investment in Us

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."

The board of directors of our general partner 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 and subordinated 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 and subordinated unitholders for so long as our Series B cumulative convertible preferred units are outstanding.

Our partnership agreement generally provides that, during the subordination period (as defined in our partnership agreement), we will pay any distributions 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, (ii) second, to the holders of common units, until each common unit has received the applicable minimum quarterly distribution plus any arrearages from prior quarters, and (iii) third, to the holders of subordinated units, until each subordinated unit has received the applicable minimum quarterly distribution. If the distributions to our common and subordinated unitholders exceed the applicable minimum quarterly distribution per unit, then such excess amounts will be distributed pro rata on the common and subordinated units as if they were a single class. Our minimum quarterly distribution is $1.35 per common and subordinated unit on an annualized basis (or $0.3375 per unit on a quarterly basis) for the four quarters ending March 31, 2019 and thereafter. We expect that we will distribute a substantial majority of the cash we generate from operations each quarter. However, the board of directors of our general partner 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 of directors of our general partner. 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 and subordinated 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 minimum quarterly distribution provides the common unitholders a specified priority right to distributions over the subordinated unitholders if we pay distributions. It does not provide the common unitholders the right to require payment of any distributions.

Our partnership agreement does not require us to pay any distributions on our common and subordinated units. The provision providing for a minimum quarterly distribution merely provides the common unitholders with a specified priority right to distributions before the subordinated unitholders receive distributions, if distributions are made with respect to the common and subordinated units.

Uncertainty associated with the end of the subordination period could result in volatility in the market price of our common units and in the amount of our quarterly cash distributions.

The subordination period under our partnership agreement will end on the first business day after we have 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 are no outstanding arrearages on our common units. This could be as early as May 2019. If the subordination period ends as a result of our having met the test described above, the subordinated units will convert into common units on a one-to-one basis. If holders of the common units resulting from conversion attempt to liquidate those common units, the market price of our common units could fall.

In addition, the elimination of the subordinated units means that all units (other than the Series B cumulative convertible preferred units) have equal priority with respect to distributions. Consequently, reductions of our quarterly cash distributions will affect all unitholders equally.

After the subordination period ends, our common unitholders will no longer be entitled to arrearages in the payment of the minimum quarterly distribution from prior quarters. The board of directors of our general partner has not yet adopted a distribution policy for periods following the subordination period. Distributions following the end of the subordination period could vary significantly from quarter to quarter, may be lower than the applicable minimum quarterly distribution, or may not be paid at all. Please read “- Risks Inherent in an Investment in Us - The board of directors of our general partner 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 and subordinated 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 and subordinated unitholders for so long as our Series B cumulative convertible preferred units are outstanding."

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 of directors of our general partner, 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.

Actions taken by our general partner may affect the amount of cash generated from operations that is available for distribution to unitholders or accelerate the right to convert subordinated units.

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, including borrowings that have the purpose or effect of:

- enabling holders of subordinated units to receive distributions; or
- hastening the expiration of the subordination period.

In addition, our general partner may use an initial amount, equal to $137.6 million, which would not otherwise constitute cash generated from operations, in order to permit the payment of distributions on subordinated units. All these actions may affect the amount of cash distributed to our unitholders and may facilitate the conversion of subordinated units into common units.

For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and our subordinated units, our partnership agreement permits us to borrow funds, which would enable us to make such distribution on all outstanding units.

We have a call right that may require common unitholders to sell their common units at an undesirable time or price.

If at any point in time prior to the end of the subordination period we have acquired more than 80% of the total number of common units outstanding, we have the right, but not the obligation, to purchase all of the remaining common units at a price equal to the greater of (1) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by us or any of our affiliates for common units during the 90-day period preceding the date such notice is first mailed. This limited call right is not exercisable as long as any of our Series B cumulative convertible preferred units are outstanding, or at any time after the subordination period has ended.

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.

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.

We may issue additional common units and other equity interests without common and subordinated unitholder approval, which would dilute holders of common and subordinated 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 and subordinated unitholders in us immediately prior to the issuance will decrease;
- the amount of cash distributions on each common and subordinated unit may decrease;
- the ratio of our taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common and subordinated 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.

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, 2018, we had 108,362,876 common units and 96,328,836 subordinated units and 14,711,219 Series B cumulative convertible preferred units outstanding. All the subordinated units could convert into common units on no more than a one-to-one basis at the end of the subordination period. 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 and an adjustment for any distributions that have accrued but not been paid when due, at any time after the second anniversary of November 28, 2017. Under certain conditions, we may elect to convert all or any portion of the Series B cumulative convertible preferred units into common units at any time after the second anniversary of November 28, 2017. 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.

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.

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.

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.

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.

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.

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 Risks to Common Unitholders

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 a "qualifying income" requirement. 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 a 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 operations and after-tax return to the 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 similar substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including a prior legislative proposal that would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no current legislative or administrative proposals, 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 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 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 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 eliminate or postpone certain tax deductions that currently are available to us or our services providers with respect to oil and gas development, or increase costs, and 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.

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. With respect to taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses/activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. 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.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a non-U.S. common unitholder’s sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. common unitholders should consult a tax advisor before investing in our common units.

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

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

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

We generally prorate our items of income, gain, loss, and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the “Allocation Date”), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, 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, he 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 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 states 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.

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.

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.” The following table sets forth the daily high and low sales price for our common units as reported by the NYSE, as well as the quarterly distributions per common and subordinated unit paid for the indicated periods.

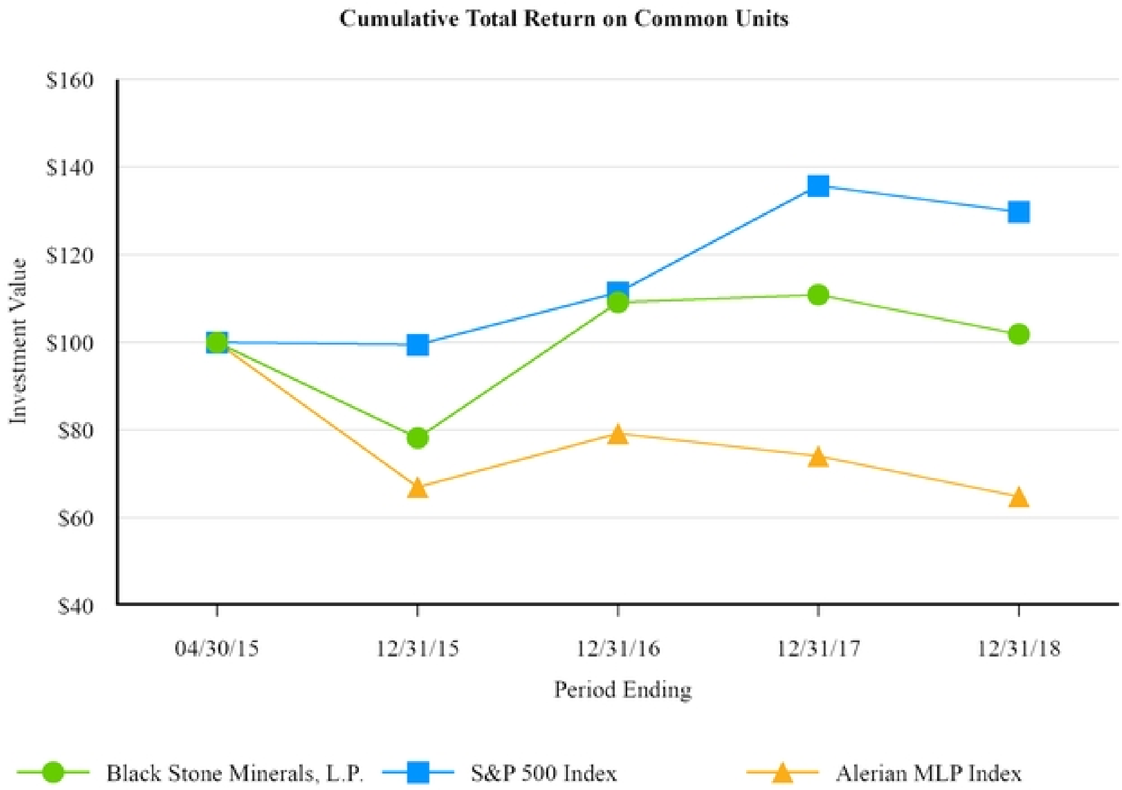
	Price Range of Common Units		Distributions[1]	
	High	Low	Per Common Unit	Per Subordinated Unit
2017				
First Quarter	$ 19.55	$ 15.58	$ 0.2875	$ 0.18375
Second Quarter	$ 17.21	$ 15.12	$ 0.3125	$ 0.20875
Third Quarter	$ 17.92	$ 15.52	$ 0.3125	$ 0.20875
Fourth Quarter	$ 18.57	$ 16.71	$ 0.3125	$ 0.20875
2018				
First Quarter	$ 19.03	$ 16.36	$ 0.3125	$ 0.20875
Second Quarter	$ 19.01	$ 16.40	$ 0.3375	$ 0.33750
Third Quarter	$ 19.29	$ 17.02	$ 0.3700	$ 0.37000
Fourth Quarter	$ 18.59	$ 15.23	$ 0.3700	$ 0.37000

[1] Represents cash distributions attributable to the quarter. Cash distributions declared in respect of a quarter are paid in the following quarter.

As of February 19, 2019, there were 108,851,353 common units outstanding held by 458 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, 2019, we also had outstanding 96,328,836 subordinated units and 14,711,219 Series B cumulative convertible preferred units. There is no established public market in which the subordinated units or the Series B cumulative convertible preferred units are traded.

Common Unit Performance Graph

The graph below compares our cumulative total unitholder return on our common units beginning on April 30, 2015, the date of pricing for our IPO, through December 31, 2018 with 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 April 30, 2015. Cumulative return is computed assuming reinvestment of distributions.



Comparison of Cumulative Total Return
Assumes Initial Investment of $100

	As of April 30, 2015	As of December 31, 2015	2016	2017	2018
Black Stone Minerals, L.P.	$ 100.00	$ 78.22	$ 109.07	$ 110.89	$ 101.80
S&P 500 Index	100.00	99.47	111.37	135.69	129.74
Alerian MLP Index	100.00	66.99	79.25	74.08	64.88

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

On October 26, 2018, we closed on the purchase of certain mineral interests using 7,664 common units valued at $0.1 million to fund the purchase price.

The issuance of the common units was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereunder.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following tables set forth our purchases of our common units for each month during the three months ended December 31, 2018:

Purchases of Common Units

Period	Total Number of Common Units Purchased	Average Price Paid Per Unit	Total Number of Common Units Purchased as Part of Publicly Announced Plans or Programs[2]	Maximum Dollar Value of Common Units That May Yet Be Purchased Under the Plans or Programs
December 1 – December 31, 2018	137,085[1]	$ 15.67	128,627	$ 72,992,543

[1] Includes units withheld to satisfy tax withholding obligations upon the vesting of certain restricted common units held by our executive officers and certain other employees.

[2] On November 5, 2018, the board of directors of our general partner authorized the repurchase of up to $75.0 million in common units. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be repurchased when we might otherwise be precluded from doing so under insider trading laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion.

Cash Distribution Policy

Our partnership agreement generally provides that we will pay any distributions each quarter during the subordination period 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;
- *second*, to the holders of common units, until each common unit has received the applicable minimum quarterly distribution in the amounts specified below plus any arrearages from prior quarters; and
- *third*, to the holders of subordinated units, until each subordinated unit has received the applicable minimum quarterly distribution.

If the distributions to our common and subordinated unitholders exceed the applicable minimum quarterly distribution per unit, then such excess amounts will be distributed pro rata on the common and subordinated units as if they were a single class. The minimum quarterly distribution is currently $1.35 per common and subordinated unit on an annualized basis (or $0.3375 per unit on a quarterly basis) for the four quarters ending March 31, 2019 and thereafter. The minimum quarterly distribution does not provide the common unitholders the right to require payment of any distributions. It merely reflects the specified priority right of our common unitholders to distributions before the subordinated unitholders receive distributions, if distributions are paid.

The amount of cash to be distributed each quarter will be determined by the board of directors of our general partner 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 of directors 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 applicable minimum quarterly distribution level on our common and subordinated units. The board of directors of our general partner 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 and subordinated units. Please read Part I, Item 1A. “Risk Factors — Risks Inherent in an Investment in Us — The board of directors of our general partner 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 and subordinated 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 and subordinated 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. Like a number of other master limited partnerships, we are required by our partnership agreement to retain cash from our operations in an amount equal to our estimated replacement capital requirements. We believe the level of our distribution rate will allow us to retain in our business sufficient cash generated from our operations to satisfy our replacement capital expenditure needs and to fund a portion of our growth capital expenditures. The board of directors of our general partner is responsible for establishing the amount of our estimated replacement capital expenditures on annual basis. On August 3, 2016, the board of directors established a replacement capital expenditure estimate of $15.0 million for the period of April 1, 2016 to March 31, 2017; there was no established estimate of replacement capital prior to this period. On June 8, 2017, the board of directors established a replacement capital expenditure estimate of $13.0 million for the period April 1, 2017 to March 31, 2018. On April 27, 2018, the board of directors approved a replacement capital expenditure estimate of $11.0 million for the period of April 1, 2018 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 of directors of our general partner and is subject to certain restrictions, including the following:

- Our common and subordinated 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 and subordinated 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 and subordinated 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 principal difference between our common and subordinated units is that, for any quarter during the subordination period, holders of the subordinated units are not entitled to receive any distribution until the holders of the common units have received the applicable minimum quarterly distribution for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units do not accrue arrearages. Our common unitholders are only entitled to arrearages in the payment of the minimum quarterly distribution from prior quarters during the subordination period. To the extent we have cash generated from operations available for distribution in any quarter during the subordination period in excess of the amount necessary to pay the applicable minimum quarterly distribution to holders of our common units, we will use this excess cash to pay any distribution arrearages on the common units related to prior quarters before any cash distribution is made on our subordinated units. Please read "Cash Distribution Policy."

The subordination period will end on the first business day after we have 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 are no outstanding arrearages on our common units. When the subordination period ends as a result of our having met the test described above, all subordinated units will convert into common units on a one-to-one basis, and common units will thereafter no longer be entitled to arrearages.

In addition, at any time on or after March 31, 2019, provided there are no arrearages in the payment of the minimum quarterly distribution on the common units, our general partner may decide in its sole discretion to convert each subordinated unit into a number of common units at a ratio that will be less than one to one. If our general partner makes such election, all outstanding subordinated units will be converted into common units, and the conversion ratio will be equal to the distributions paid out with respect to the subordinated units over the previous four-quarter period in relation to the total amount of distributions required to pay the applicable minimum quarterly distribution in full with respect to the subordinated units over the previous four quarters. If at the time our general partner elects to convert the subordinated units under this provision our forecasted distributions on our subordinated units (as determined by the conflicts committee of our general partner's board of directors) for the next four quarters are lower than our actual distributions for the previous four-quarter period referred to above, then the conversion ratio will be based on the forecasted distributions instead of the actual distributions.

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 will 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 commencing after the second anniversary of November 28, 2017 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 and subordinated units, prior to paying the quarterly distribution payable to the Series B cumulative convertible preferred units, including any previously accrued and unpaid distributions.

ITEM 6. SELECTED FINANCIAL DATA

The financial information below should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

	At December 31,				
	2018	**2017**	**2016**	**2015**	**2014**
	(in thousands, except per unit amounts)				
Total revenue	$ 609,568	$ 429,659	$ 260,833	$ 392,924	$ 548,321
Net income (loss)	295,560	157,153	20,188	(101,305)	169,187
Net income (loss) attributable to the general partner and common units and subordinated units	274,511	152,145	14,437	(108,017)	*
Net income (loss) attributable to limited partners per common and subordinated unit (basic)[1]					
Per common unit (basic)	1.46	1.01	0.26	(0.56)	*
Per subordinated unit (basic)	1.25	0.56	(0.11)	(0.56)	*
Net income (loss) attributable to limited partners per common and subordinated unit (diluted)[1]					
Per common unit (diluted)	1.45	1.01	0.26	(0.56)	*
Per subordinated unit (diluted)	1.25	0.56	(0.11)	(0.56)	*
Cash distributions declared per common and subordinated unit					
Per common unit	$ 1.33	$ 1.20	$ 1.10	$ 0.42	*
Per subordinated unit	$ 1.13	$ 0.79	$ 0.74	$ 0.42	*
Total assets[2]	$ 1,750,124	$ 1,576,451	$ 1,128,827	$ 1,061,436	$ 1,326,782
Long-term debt	410,000	388,000	316,000	66,000	394,000
Total mezzanine equity	298,361	322,422	54,015	79,162	161,165

* Information is not applicable for the periods prior to our IPO.

[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 $6.8 million, $249.6 million, and $117.9 million for the years ended December 31, 2016, 2015, and 2014, respectively. We did not have impairments of oil and natural gas properties for the years ended December 31, 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."

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 the marketing of 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. Our primary business objective is to grow our reserves, production, and cash generated from operations over the long term, while paying, to the extent practicable, a growing quarterly distribution to our unitholders.

As of December 31, 2018, 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 60,000 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

Acquisitions

In 2018 we acquired mineral and royalty interests primarily in the Permian Basin and in East Texas for aggregate consideration of $127.3 million in cash and $22.6 million in our common units. Additional information regarding acquisitions is contained in Note 4 – Oil and Natural Gas Properties Acquisitions to our consolidated financial statements included elsewhere in this Annual Report.

PepperJack Prospect

We have cumulatively spent approximately $13.1 million to drill two wells within our PepperJack prospect in Hardin and Liberty counties, Texas. The PepperJack A#1 well targeting the Lower Wilcox formation was drilled during the fourth quarter of 2017 and the first quarter of 2018. The PepperJack B#1 well, also targeting the Lower Wilcox formation, was drilled during the second quarter of 2018 to further delineate the prospect.

Based on the log results, we believe the PepperJack A#1 well is highly prospective and will be completed as a commercially productive well. The PepperJack B#1 well, which was a significant step-out from the PepperJack A#1 well, is not likely to be completed in the near term. Accordingly, we have recorded $6.8 million of costs for the PepperJack B#1 well to the Exploration expense line item of the consolidated statements of operations for the year ended December 31, 2018.

On September 21, 2018, we entered into an exploration agreement with a consortium of private exploration and production companies (the "Development Partners") to further delineate and develop the PepperJack prospect. As part of the agreement, we assigned 75% of our working interest in the PepperJack A#1 well and acreage in the associated unit to the Development Partners and transferred our status as the operator of record. We received proceeds of $6.4 million for the assignment, which represented a reimbursement for 100% of the drilling costs and associated acreage, proceeds of $1.0 million for an option covering our minerals and leases in the PepperJack prospect area, and an overriding royalty interest in the PepperJack prospect area. The Development Partners began completion operations on the PepperJack A#1 well in the fourth quarter of 2018 and we are participating as a 25% non-operated working interest owner.

Common Unit Repurchase Program

In the fourth quarter of 2018, the board of directors of our general partner authorized a $75.0 million common unit repurchase program. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be repurchased when we might otherwise be precluded from doing so under applicable laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion. We will periodically report the number of common units repurchased. In 2018, we repurchased a total of 128,627 common units for an aggregate cost of $2.0 million. The program is funded from cash on hand or through borrowings under the credit facility. Any repurchased units are canceled.

Business Environment

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

Commodity Prices and Demand

Oil and natural gas prices have been historically volatile based upon the dynamics of supply and demand. The EIA forecasts that WTI oil prices will average approximately $54.79 per Bbl in 2019 and $58.00 per Bbl in 2020. During the year ended December 31, 2018, the WTI oil spot price reached a high of $77.41 per Bbl on June 27, 2018 but decreased to a low of $44.48 per Bbl on December 27, 2018.

The EIA forecasts that the Henry Hub spot natural gas price will average $2.83 per MMBtu for 2019 and $2.80 per MMBtu for 2020. During the year ended December 31, 2018, Henry Hub spot natural gas prices ranged from a high of $6.24 per MMBtu on January 3, 2018 to a low of $2.49 per MMBtu on February 16, 2018.

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:

	2018			
Benchmark Prices	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot crude oil ($/Bbl)[1]	$ 45.15	$ 73.16	$ 74.13	$ 64.87
Henry Hub spot natural gas ($/MMBtu)[1]	$ 3.25	$ 3.01	$ 2.96	$ 2.81

[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:

	2018			
U.S. Rotary Rig Count[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	885	863	858	797
Natural gas	198	189	187	194
Other	—	2	2	2
Total	1,083	1,054	1,047	993

[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 2019, at 1,417 Bcf, or 14% below the five-year average. The EIA expects inventories to build slightly over the five-year average to a projected 3,761 Bcf at the end of October 2019; in 2020, inventories are expected to be about 5% higher on average than 2019 levels.

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

	2018			
Region[1]	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
	(Bcf)			
East	661	763	460	229
Midwest	798	836	455	266
Mountain	147	177	139	87
Pacific	220	262	257	166
South Central	878	829	841	606
Total	2,704	2,867	2,152	1,354

[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

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

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

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

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

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

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

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

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

Hedging

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

Our open derivative contracts consist of fixed-price swap contracts 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 receive the fixed ceiling price from the counterparty and we pay the market price. If the market price is below the fixed floor price, we receive the fixed floor price and we pay the market 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, 2018 are detailed in Note 5 – Commodity Derivative Financial Instruments to our consolidated financial statements included elsewhere in this Annual Report.

Prior to amending and restating our credit agreement on November 1, 2017, we were allowed to hedge all of our estimated production from our proved developed producing reserves based on the most recent reserve information provided to our lenders. Pursuant to our Fourth Amended and Restated Credit Agreement, 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. Pursuant to our updated hedge provisions, as of December 31, 2018 we have hedged, 70.2%, and 20.9% of our available oil and condensate hedge volumes for 2019 and 2020, respectively. Also, as of December 31, 2018 we have hedged 93.2% of our available natural gas hedge volumes for 2019.

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, and non-cash equity-based compensation. We define distributable cash flow as Adjusted EBITDA plus or minus amounts for certain non-cash operating activities, estimated replacement capital expenditures, cash interest expense, and distributions to noncontrolling interests and preferred unitholders.

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 in the United States (“U.S. GAAP”) 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 U.S. 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 U.S. GAAP financial measure, to Adjusted EBITDA and distributable cash flow for the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Net income (loss)	$ 295,560	$ 157,153	$ 20,188
Adjustments to reconcile to Adjusted EBITDA:			
Depreciation, depletion and amortization	122,653	114,534	102,487
Interest expense	20,756	15,694	7,547
Income tax expense	2,309	—	—
Impairment of oil and natural gas properties	—	—	6,775
Accretion of asset retirement obligations	1,103	1,026	892
Equity-based compensation[1]	30,134	33,045	43,138
Unrealized (gain) loss on commodity derivative instruments	(53,066)	(11,691)	81,253
Adjusted EBITDA	419,449	309,761	262,280
Adjustments to distributable cash flow:			
Change in deferred revenue	1,260	(2,086)	(870)
Cash interest expense	(19,757)	(14,817)	(6,676)
(Gain) loss on sales of assets, net	(3)	(931)	(4,793)
Estimated replacement capital expenditures[2]	(11,500)	(13,500)	(11,250)
Cash paid to noncontrolling interests	(211)	(120)	(111)
Preferred unit distributions	(21,025)	(5,042)	(5,763)
Distributable cash flow	$ 368,213	$ 273,265	$ 232,817

[1] On April 25, 2016, the Compensation Committee of the board of directors of our general partner approved a resolution to change the settlement feature of certain employee long-term incentive compensation plans from cash to equity. As a result of the modification, $10.1 million of cash-settled liabilities were reclassified to equity-settled liabilities during the second quarter of 2016.

[2] On August 3, 2016, the board of directors of our general partner established a replacement capital expenditures estimate of $15.0 million for the period of April 1, 2016 to March 31, 2017; there was no established estimate of replacement capital expenditures prior to this period. On June 8, 2017, the board of directors of our general partner established a replacement capital expenditure estimate of $13.0 million for the period of April 1, 2017 to March 31, 2018. On April 27, 2018, the Board approved a replacement capital expenditure estimate of $11.0 million for the period of April 1, 2018 to March 31, 2019.

Results of Operations

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

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

	Year Ended December 31,			
	2018	2017	Variance	
	(dollars in thousands, except for realized prices and per BOE data)			
Production:				
Oil and condensate (MBbls)	4,962	3,552	1,410	39.7 %
Natural gas (MMcf)[1]	71,622	59,779	11,843	19.8 %
Equivalents (MBoe)	16,899	13,515	3,384	25.0 %
Revenue:				
Oil and condensate sales	$ 310,278	$ 169,728	$ 140,550	82.8 %
Natural gas and natural gas liquids sales[1]	248,243	190,967	$ 57,276	30.0 %
Lease bonus and other income	36,216	42,062	$ (5,846)	(13.9)%
Revenue from contracts with customers	594,737	402,757	$ 191,980	47.7 %
Gain (loss) on commodity derivative instruments	14,831	26,902	$ (12,071)	(44.9)%
Total revenue	609,568	429,659	179,909	41.9 %
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 62.53	$ 47.78	$ 14.75	30.9 %
Natural gas ($/Mcf)[1]	$ 3.47	3.19	0.28	8.8 %
Equivalents ($/Boe)	$ 33.05	$ 26.69	$ 6.36	23.8 %
Operating expenses:				
Lease operating expense	$ 18,415	$ 17,280	$ 1,135	6.6 %
Production costs and ad valorem taxes	64,364	47,474	16,890	35.6 %
Exploration expense	7,943	618	7,325	NM[2]
Depreciation, depletion, and amortization	122,653	114,534	8,119	7.1 %
General and administrative	76,712	77,574	(862)	(1.1)%

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

Revenue

Total revenue for the year ended December 31, 2018 increased compared to the year ended December 31, 2017. The increase in total revenue from the corresponding period is primarily due to increased oil and condensate sales and natural gas and NGL sales as a result of increased production volumes and higher realized commodity prices, partially offset by a decreased gain from our commodity derivative instruments and lower lease bonus and other income. Production for 2018 averaged 46.3 MBoe per day, an increase of 9.3 MBoe per day, compared to the corresponding period in 2017.

Oil and condensate sales. Oil and condensate sales for the year ended December 31, 2018 were higher than the corresponding period in 2017 due to increased production volumes and higher realized commodity prices. Our mineral and royalty interest oil and condensate volumes increased 52% in 2018 relative to 2017, primarily driven by production increases in the Permian-Midland, Permian-Delaware, and Bakken/Three Forks plays. Our mineral and royalty interest oil and condensate volumes accounted for 90% and 83% of total oil and condensate volumes for the years ended December 31, 2018 and 2017, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales for the year ended December 31, 2018 were higher than the corresponding period in 2017 primarily due to increased production volumes, largely in the Haynesville/Bossier play, as well as the Permian-Midland, Permian-Delaware, and Bakken/Three Forks plays. Mineral and royalty interest production accounted for 60% and 51% of our natural gas and NGL volumes for the years ended December 31, 2018 and 2017, respectively. There was also an increase in commodity prices between the comparative periods.

Gain (loss) on commodity derivative instruments. In 2018, we recognized a decreased gain from our commodity derivative instruments compared to the same period of 2017. 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. In 2018, we recognized $24.3 million of net gains from oil commodity contracts, which included cash payments of $34.9 million, compared to $5.1 million of recognized net losses in 2017. In 2018, we recognized $9.5 million of net losses from natural gas commodity contracts, which included cash payments of $3.3 million, compared to $32.0 million of net gains in 2017.

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, 2018, as compared to the same period 2017, though we successfully closed several significant lease transactions in the Bakken/Three Forks, Haynesville/Bossier, Permian-Midland, Permian-Delaware, and Austin Chalk plays.

<u>Operating Expenses</u>

Lease operating expense. Lease operating expense includes recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense increased for the year ended December 31, 2018 as compared to 2017, primarily due to higher workover and other service-related expenses on wells in which we own a non-operating working interest.

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, 2018, production and ad valorem taxes increased over the year ended December 31, 2017, generally as a result of higher production volumes and commodity prices.

Exploration expense. Exploration expense typically consists of dry-hole expenses, delay rentals, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense for 2018 primarily related to the PepperJack B#1 well. Exploration expense for 2017 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 increased for the year ended December 31, 2018 as compared to 2017, primarily due to higher production volumes partially offset by lower depletion rates.

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, 2018, general and administrative expenses remained relatively flat compared to 2017 due to lower brokerage and legal fees associated with our acquisition activity, partially offset by increased costs attributable to our incentive compensation plans.

Interest expense. Interest expense increased due to higher average outstanding borrowings and higher interest rates under our credit facility. The increase in average outstanding borrowings was primarily due to funding of acquisitions during 2018.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

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

	Year Ended December 31,			
	2017	2016	Variance	
	(dollars in thousands, except for realized prices and per BOE data)			
Production:				
Oil and condensate (MBbls)	3,552	3,680	(128)	(3.5)%
Natural gas (MMcf)[1]	59,779	47,498	12,281	25.9 %
Equivalents (MBoe)	13,515	11,596	$ 1,919	16.5 %
Revenue:				
Oil and condensate sales	$ 169,728	$ 142,382	$ 27,346	19.2 %
Natural gas and natural gas liquids sales[1]	190,967	122,836	68,131	55.5 %
Lease bonus and other income	42,062	32,079	9,983	31.1 %
Revenue from contracts with customers	402,757	297,297	105,460	35.5 %
Gain (loss) on commodity derivative instruments	26,902	(36,464)	63,366	(173.8)%
Total revenue	$ 429,659	$ 260,833	168,826	64.7 %
Realized prices:				
Oil and condensate ($/Bbl)	$ 47.78	$ 38.69	$ 9.09	23.5 %
Natural gas ($/Mcf)[1]	3.19	2.59	0.60	23.2 %
Equivalents ($/Boe)	$ 26.69	$ 22.87	$ 3.82	16.7 %
Operating expenses:				
Lease operating expense	$ 17,280	$ 18,755	$ (1,475)	(7.9)%
Production costs and ad valorem taxes	47,474	35,464	12,010	33.9 %
Exploration expense	618	645	(27)	(4.2)%
Depreciation, depletion, and amortization	114,534	102,487	12,047	11.8 %
Impairment of oil and natural gas properties	—	6,775	(6,775)	(100.0)%
General and administrative	77,574	73,139	4,435	6.1 %

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

Revenue

Total revenue for the year ended December 31, 2017 increased compared to the year ended December 31, 2016. Production for 2017 averaged 37.0 MBoe per day, an increase of 5.3 MBoe per day, compared to the corresponding period in 2016. The increase in total revenue from the corresponding period is primarily due to higher realized commodity prices and production volumes, an increase in revenue from our commodity derivative instruments, and higher lease bonus and other income.

Oil and condensate sales. Oil and condensate sales during 2017 were higher than the corresponding period in 2016 due to a significant increase in realized prices. Our mineral and royalty interest oil and condensate volumes accounted for 83% and 77% of total oil and condensate volumes for the years ended December 31, 2017 and 2016, respectively. Our oil and condensate volumes decreased slightly in 2017.

Natural gas and natural gas liquids sales. Natural gas and NGL sales increased for the year ended December 31, 2017 as compared to 2016. During 2017, production from new wells in Haynesville/Bossier and Wilcox plays combined with higher natural gas and NGL prices drove the increase in natural gas and NGL sales. Mineral and royalty interest production accounted for 51% and 59% of our natural gas and NGL volumes for the years ended December 31, 2017 and 2016, respectively.

Gain (loss) on commodity derivative instruments. In 2017, we recognized $5.1 million of net losses from oil commodity contracts, which included cash received of $10.9 million, compared to $16.0 million of recognized net losses in 2016. In 2017, we recognized $32.0 million of net gains from natural gas commodity contracts, which included cash received of $4.3 million, compared to $20.5 million of net losses in 2016.

Lease bonus and other income. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Lease bonus and delay rental revenue increased for the year ended December 31, 2017, as compared to 2016. In 2017, we successfully closed several significant lease transactions in the Austin Chalk, Bakken/Three Forks, Haynesville/Bossier and Canyon Lime plays as well as the Anadarko and Permian Basins, compared to the majority of 2016 activity which came from the Wolfcamp, Austin Chalk, and Marcellus plays.

Operating Expenses

Lease operating expense. Lease operating expense includes normally recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased for the year ended December 31, 2017 as compared to 2016, primarily due to fewer remedial projects initiated by our operators.

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, 2017, production and ad valorem taxes increased over the year ended December 31, 2016, generally as a result of higher production volumes and commodity prices.

Exploration expense. Exploration expense typically consists of dry-hole expenses, delay rentals, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense for 2017 represents 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 increased for the year ended December 31, 2017 as compared to 2016, primarily due to higher production volumes partially offset by lower depletion rates.

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. We did not incur any impairment in 2017, while impairments for 2016 were $6.8 million.

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, 2017, general and administrative expenses increased compared to 2016. In 2017, costs attributable to our long-term incentive plans were higher due to the achievement of certain performance targets; we also incurred higher broker fees associated with increased acquisition activities.

Interest expense. Interest expense increased due to higher average outstanding borrowings and higher interest rates under our credit facility, which were predominantly driven by increased acquisition of oil and natural gas properties in 2017 as compared to 2016.

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 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 of directors of our general partner has adopted a policy pursuant to which, at a minimum, distributions will be paid on each common and subordinated 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 and subordinated units quarterly or on any other basis, and there is no guarantee that we will pay distributions to our common and subordinated unitholders in any quarter. Our minimum quarterly distribution provides the common unitholders a specified priority right to distributions over the subordinated unitholders. The priority right will cease to exist upon full conversion of the subordinated units to common units, which may occur as early as May of 2019. The board of directors of our general partner 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. Like a number of other master limited partnerships, we are required by our partnership agreement to retain cash from our operations in an amount equal to our estimated replacement capital requirements. The board of directors of our general partner established a replacement capital expenditure estimate of $15.0 million for the period of April 1, 2016 to March 31, 2017, $13.0 million for the period of April 1, 2017 to March 31, 2018, and $11.0 million for the period of April 1, 2018 to March 31, 2019.

Cash Flows

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

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

	Year Ended December 31,		
	2018	**2017**	**Change**
		(in thousands)	
Cash flows provided by operating activities	$ 385,378	$ 281,852	$ 103,526
Cash flows used in investing activities	(163,804)	(454,249)	290,445
Cash flows provided by (used in) financing activities	(221,802)	168,267	(390,069)

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. The increase in cash flows from operations in 2018 as compared to 2017 was primarily due to higher commodity revenue driven by increased oil and natural gas production and higher realized commodity prices period over period, partially offset by the net cash paid on settlement of commodity derivative instruments for 2018 compared to cash received for the same period of 2017.

Investing Activities. Net cash used in investing activities decreased in 2018 as compared to 2017. The decrease was primarily due to less cash spent on acquisitions and higher proceeds received from our farmout agreements, partially offset by an increase in cash spent on additions to oil and natural gas properties.

Financing Activities. For the year ended December 31, 2018, cash flows were used in financing activities and was a result of increased distributions to common and subordinated unitholders, distributions to holders of Series B cumulative convertible preferred units, and a decrease in net borrowings under our credit facility as compared to 2017. During 2017, cash flows were primarily provided by proceeds from the issuance of the Series B cumulative convertible preferred units and the issuance of common units under our ATM program.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

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

	Year Ended December 31,		
	2017	**2016**	**Change**
		(in thousands)	
Cash flows provided by operating activities	$ 281,852	$ 196,656	$ 85,196
Cash flows used in investing activities	(454,249)	(221,542)	(232,707)
Cash flows provided by (used in) financing activities	168,267	21,425	146,842

Operating Activities. Our operating cash flow is dependent, in large part, on our production, realized commodity prices, leasing revenues, and operating expenses. The increase in cash flows from operations in 2017 as compared to 2016 was primarily due to increased oil and natural gas revenue driven by higher oil and natural gas sales, an increase in lease bonus and other income, as well as changes in working capital, which was partially offset by increased production costs and ad valorem taxes and general and administrative expenses, as well as a decrease in net cash received on the settlement of commodity derivative financial instruments.

Investing Activities. Net cash used in investing activities increased in 2017 as compared to 2016. The increase was primarily due to the cash portion of oil and natural gas properties acquisitions in 2017 being higher than the cash portion of oil and natural gas properties acquisitions in 2016, which was partially offset by increased proceeds from the sale of oil and natural gas properties and proceeds from farmouts of oil and natural gas properties.

Financing Activities. Cash flows provided by financing activities increased in 2017 as compared to 2016. The increase was primarily due to proceeds from the issuance of common units under our ATM Program and proceeds from the issuance of the Series B cumulative convertible preferred units. Decreased distributions to holders of the Series A redeemable preferred units and decreased repurchases of common and subordinated units also contributed to the net increase in financing cash flows. These 2017 increases were partially offset by increased distributions to common and subordinated unitholders and a decrease in net borrowings under our credit facility compared to 2016.

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 2019 capital expenditure budget associated with our non-operated working interests is expected to be approximately $10.0 million. The majority of this capital will be 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.

During 2018, we spent approximately $36.3 million associated with our non-operated working interests in certain Haynesville/Bossier wells in the Shelby Trough area of East Texas, net of farmout reimbursements, related to completions in wells which were spud prior to the farmouts. In the PepperJack prospect area, we spent approximately $11.9 million during 2018 to drill and log two wells targeting the Lower Wilcox formation. We spent an additional $0.5 million related to the completion costs for the PepperJack A#1 well in the fourth quarter of 2018.

We spent approximately $58.6 million and $73.3 million related to drilling and completion costs for the years ended December 31, 2017 and 2016, respectively. During 2017, our capital expenditures were offset by proceeds from farmout reimbursements of approximately $19.2 million.

Acquisitions

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.

During 2017, we spent approximately $425.7 million and issued common units valued at $71.7 million related to acquisitions of mineral and royalty interests, which also included proved oil and natural gas properties.

During 2016, we spent approximately $141.1 million related to four mineral acquisitions as well as a final holdback payment from an acquisition in 2015.

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

Credit Facility

Pursuant to our $1.0 billion secured revolving credit agreement, 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. On November 1, 2017, we entered into the fourth amended and restated credit agreement to extend the maturity date thereof for a term of five years, create a swingline facility that permits short-term borrowings on same-day notice, and make other changes to the hedging and restrictive covenants. The borrowing base was reconfirmed at $550.0 million with our fall 2017 redetermination. Effective May 4, 2018, the borrowing base was increased to $600.0 million with our spring 2018 redetermination, and effective October 31, 2018, the borrowing base was further increased to $675.0 million with our fall 2018 redetermination. Our credit facility terminates on November 1, 2022. As of December 31, 2018, we had outstanding borrowings of $410.0 million at a weighted-average interest rate of 4.76%.

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. Under the fourth amended and restated credit agreement, we also have the right to request a redetermination following acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition.

Outstanding borrowings under the credit agreement 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. Through October 2016, the applicable margin ranged from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of borrowings outstanding in relation to the borrowing base. Subsequent to the closing of our fall redetermination on October 31, 2016, the applicable margin ranges 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 LIBOR margin was reduced to between 1.75% and 2.75% and the Prime Rate margin was reduced to between 0.75% and 1.75%.

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 liens on substantially all of our producing properties.

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 swap 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 modified 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 due to a 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, 2018, we were in compliance with all debt covenants.

Contractual Obligations

The following table summarizes our minimum payments as of December 31, 2018 (in thousands):

		Payments due by period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Credit facility	$ 410,000	$ —	$ —	$ 410,000	$ —
Operating lease obligations	6,992	1,386	2,756	2,850	—
Purchase commitments	886	813	73	—	—
Total	$ 417,878	$ 2,199	$ 2,829	$ 412,850	$ —

Off-Balance Sheet Arrangements

At December 31, 2018, 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 U.S. 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 considered business combinations and are recorded at their estimated fair value as of the acquisition date. Acquisitions of unproved oil and natural gas properties are 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 may 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 $122.5 million, $114.3 million, and $102.4 million for the years ended December 31, 2018, 2017, and 2016, 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, future capital expenditures, and a risk-adjusted discount rate.

There was no impairment of proved oil and natural gas properties for the years ended December 31, 2018 and 2017. Impairment of proved oil and natural gas properties was $4.9 million for the year ended December 31, 2016. The impairment primarily resulted from declines in future expected realizable net cash flows. The charge is included in impairment of oil and natural gas properties on the consolidated statements of operations and reflected in the net book value of oil and natural gas properties.

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, 2018 and 2017. Impairment of unproved properties was $1.9 million for the year ended December 31, 2016. The charge is included in impairment of oil and natural gas properties on the consolidated statements of operations and reflected in the net book value of oil and natural gas properties.

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, 2018 reserve report. Applying this discount results in an approximate 1.7% reduction of estimated proved reserve volumes as compared to the undiscounted pricing scenario used in our December 31, 2018 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 U.S. 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, 2018 and 2017, 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 sheet. 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 of directors of our general partner. 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 estimates, are likely to vest, by the grant-date fair value and recognized using the accelerated attribution method. 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 on a designated floating price. The designated floating 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, 2018. Applying this discount results in an approximate 1.7% reduction of proved reserve volumes as compared to the undiscounted December 31, 2018 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, 2018, we had ten counterparties, all of which are rated Baa1 or better by Moody's. Nine of our counterparties 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, 2018, we had $410.0 million of outstanding borrowings under our credit facility, bearing interest at a weighted-average interest rate of 4.76%. 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 $4.1 million for the year ended December 31, 2018, 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, 2018 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 U.S. 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, 2018, 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, 2018.

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, 2018, which is included in the Annual Report on page F-3.

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, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

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 2019 Annual Meeting of Limited Partners ("2019 Proxy Statement"), which will be filed with the SEC not later than 120 days after December 31, 2018.

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 2019 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2018.

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 2019 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2018.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2018.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by this item is incorporated by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2018.

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
2.1**	Purchase and Sale Agreement, dated as of November 22, 2017, by and among Noble Energy Inc., Noble Energy Wyco, LLC, Noble Energy US Holdings, LLC, Rosetta Resources Operating LP, and Black Stone Minerals Company, L.P. (incorporated herein by reference to Exhibit 2.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362))
3.1	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	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^	Employment Agreement by and between Black Stone Minerals Company, L.P. and Thomas L. Carter, Jr. effective as of April 1, 2009 (incorporated herein by reference to Exhibit 10.3 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
10.6^	First Amendment to Employment Agreement by and between Black Stone Minerals Company, L.P. and Thomas L. Carter, Jr. effective as of June 25, 2014 (incorporated herein by reference to Exhibit 10.4 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
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*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Schema Document.
101.CAL*	XBRL Taxonomy Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Label Linkbase Document.
101.PRE*	XBRL Taxonomy Presentation Linkbase Document.

* Filed herewith.

** Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Partnership agrees to furnish supplementally a copy of the omitted schedules and exhibits to the SEC upon request.

^ 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 26, 2019

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 26, 2019
/s/ Jeffrey P. Wood Jeffrey P. Wood	President and Chief Financial Officer (Principal Financial Officer)	February 26, 2019
/s/ Dawn K. Smajstrla Dawn K. Smajstrla	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2019
/s/ William G. Bardel William G. Bardel	Director	February 26, 2019
/s/ Carin M. Barth Carin M. Barth	Director	February 26, 2019
/s/ D. Mark DeWalch D. Mark DeWalch	Director	February 26, 2019
/s/ Ricky J. Haeflinger Ricky J. Haeflinger	Director	February 26, 2019
/s/ Jerry V. Kyle, Jr. Jerry V. Kyle, Jr.	Director	February 26, 2019
/s/ Michael C. Linn Michael C. Linn	Director	February 26, 2019
/s/ John H. Longmaid John H. Longmaid	Director	February 26, 2019
/s/ William N. Mathis William N. Mathis	Director	February 26, 2019
/s/ William E. Randall William E. Randall	Director	February 26, 2019
/s/ Alexander D. Stuart Alexander D. Stuart	Director	February 26, 2019
/s/ Allison K. Thacker Allison K. Thacker	Director	February 26, 2019

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, 2018 and 2017, the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 26, 2019 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.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2016.
Houston, Texas
February 26, 2019

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, 2018, 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, 2018, 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, 2018 and 2017, the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and our report dated February 26, 2019 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 26, 2019

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

	As of December 31,	
	2018	**2017**
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 5,414	$ 5,642
Accounts receivable	113,148	80,695
Commodity derivative assets	37,970	94
Prepaid expenses and other current assets	1,001	1,212
TOTAL CURRENT ASSETS	157,533	87,643
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $1,063,883 and $988,720 at December 31, 2018 and 2017, respectively	3,441,188	3,247,613
Accumulated depreciation, depletion, amortization, and impairment	(1,865,692)	(1,766,842)
Oil and natural gas properties, net	1,575,496	1,480,771
Other property and equipment, net of accumulated depreciation of $11,048 and $14,433 at December 31, 2018 and 2017, respectively	385	559
NET PROPERTY AND EQUIPMENT	1,575,881	1,481,330
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	16,710	7,478
TOTAL ASSETS	$ 1,750,124	$ 1,576,451
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 4,149	$ 2,464
Accrued liabilities	60,089	52,631
Commodity derivative liabilities	—	4,222
Other current liabilities	528	417
TOTAL CURRENT LIABILITIES	64,766	59,734
LONG-TERM LIABILITIES		
Credit facility	410,000	388,000
Accrued incentive compensation	1,813	3,648
Commodity derivative liabilities	—	1,263
Asset retirement obligations	14,948	14,092
Other long-term liabilities	55,973	19,171
TOTAL LIABILITIES	547,500	485,908
COMMITMENTS AND CONTINGENCIES (Note 11)		
MEZZANINE EQUITY		
Partners' equity — Series A redeemable preferred units, zero and 26 units outstanding at December 31, 2018 and 2017, respectively	—	27,028
Partners' equity — Series B cumulative convertible preferred units, 14,711 and 14,711 units outstanding at December 31, 2018 and 2017, respectively	298,361	295,394
EQUITY		
Partners' equity — general partner interest	—	—
Partners' equity — common units, 108,363 and 103,456 units outstanding at December 31, 2018 and 2017, respectively	714,823	603,116
Partners' equity — subordinated units, 96,329 and 95,388 units outstanding at December 31, 2018 and 2017, respectively	189,440	164,138
Noncontrolling interests	—	867
TOTAL EQUITY	904,263	768,121
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,750,124	$ 1,576,451

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

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

	Year Ended December 31, 2018	2017	2016
REVENUE			
Oil and condensate sales	$ 310,278	$ 169,728	$ 142,382
Natural gas and natural gas liquids sales	248,243	190,967	122,836
Lease bonus and other income	36,216	42,062	32,079
Revenue from contracts with customers	594,737	402,757	297,297
Gain (loss) on commodity derivative instruments	14,831	26,902	(36,464)
TOTAL REVENUE	609,568	429,659	260,833
OPERATING (INCOME) EXPENSE			
Lease operating expense	18,415	17,280	18,755
Production costs and ad valorem taxes	64,364	47,474	35,464
Exploration expense	7,943	618	645
Depreciation, depletion and amortization	122,653	114,534	102,487
Impairment of oil and natural gas properties	—	—	6,775
General and administrative	76,712	77,574	73,139
Accretion of asset retirement obligations	1,103	1,026	892
(Gain) loss on sale of assets, net	(3)	(931)	(4,793)
TOTAL OPERATING EXPENSE	291,187	257,575	233,364
INCOME (LOSS) FROM OPERATIONS	318,381	172,084	27,469
OTHER INCOME (EXPENSE)			
Interest and investment income	183	49	656
Interest expense	(20,756)	(15,694)	(7,547)
Other income (expense)	(2,248)	714	(390)
TOTAL OTHER EXPENSE	(22,821)	(14,931)	(7,281)
NET INCOME (LOSS)	295,560	157,153	20,188
Net (income) loss attributable to noncontrolling interests	(24)	34	12
Distributions on Series A redeemable preferred units	(25)	(3,117)	(5,763)
Distributions on Series B cumulative convertible preferred units	(21,000)	(1,925)	—
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	$ 274,511	$ 152,145	$ 14,437
ALLOCATION OF NET INCOME (LOSS):			
General partner interest	$ —	$ —	$ —
Common units	154,662	98,389	24,669
Subordinated units	119,849	53,756	(10,232)
	$ 274,511	$ 152,145	$ 14,437
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:			
Per common unit (basic)	$ 1.46	$ 1.01	$ 0.26
Weighted average common units outstanding (basic)	106,064	97,400	96,073
Per subordinated unit (basic)	$ 1.25	$ 0.56	$ (0.11)
Weighted average subordinated units outstanding (basic)	96,099	95,149	95,138
Per common unit (diluted)	$ 1.45	$ 1.01	$ 0.26
Weighted average common units outstanding (diluted)	121,264	97,400	96,243
Per subordinated unit (diluted)	$ 1.25	$ 0.56	$ (0.11)
Weighted average subordinated units outstanding (diluted)	96,346	95,149	95,138

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, 2015	96,162	95,057	$ 574,648	$ 255,699	$ 1,144	$ 831,491
Conversion of Series A redeemable preferred units	184	241	2,625	3,439	—	6,064
Repurchases of common and subordinated units	(1,618)	(78)	(27,436)	—	—	(27,436)
Restricted common and subordinated units granted, net of forfeitures	993	(56)	—	—	—	—
Equity-based compensation	—	—	21,022	2,823	—	23,845
Distributions	—	—	(105,817)	(70,127)	(111)	(176,055)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(688)	—	—	(688)
Net income (loss)	—	—	27,565	(7,365)	(12)	20,188
Distributions on Series A redeemable preferred units	—	—	(2,896)	(2,867)	—	(5,763)
BALANCE AT DECEMBER 31, 2016	95,721	95,164	$ 489,023	$ 181,602	$ 1,021	$ 671,646
Conversion of Series A redeemable preferred units	201	263	2,868	3,756	—	6,624
Repurchases of common and subordinated units	(446)	(39)	(7,893)	(292)	—	(8,185)
Issuance of common units, net of offering costs	2,002	—	32,458	—	—	32,458
Issuance of common units for property acquisitions	4,348	—	71,723	—	—	71,723
Restricted units granted, net of forfeitures	1,630	—	—	—	—	—
Equity-based compensation	—	—	39,205	152	—	39,357
Distributions	—	—	(119,963)	(74,836)	(120)	(194,919)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(2,694)	—	—	(2,694)
Net income (loss)	—	—	101,891	55,296	(34)	157,153
Distributions on Series A redeemable preferred units	—	—	(1,577)	(1,540)	—	(3,117)
Distributions on Series B cumulative convertible preferred units	—	—	(1,925)	—	—	(1,925)
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

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,		
	2018	**2017**	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	295,560	$ 157,153	$ 20,188
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	122,653	114,534	102,487
Impairment of oil and natural gas properties	—	—	6,775
Accretion of asset retirement obligations	1,103	1,026	892
Amortization of deferred charges	905	877	871
(Gain) loss on commodity derivative instruments	(14,831)	(26,902)	36,464
Net cash (paid) received on settlement of commodity derivative instruments	(38,235)	15,211	44,789
Equity-based compensation	30,134	33,044	43,138
Exploratory dry hole expense	6,785	—	—
Deferred rent	1,283	—	—
(Gain) loss on sale of assets, net	(3)	(931)	(4,793)
Changes in operating assets and liabilities:			
Accounts receivable	(31,531)	(6,084)	(29,759)
Prepaid expenses and other current assets	210	(177)	(180)
Accounts payable, accrued liabilities, and other	11,474	(5,671)	(23,899)
Settlement of asset retirement obligations	(129)	(228)	(317)
NET CASH PROVIDED BY OPERATING ACTIVITIES	385,378	281,852	196,656
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisitions of oil and natural gas properties	(124,081)	(425,667)	(141,136)
Additions to oil and natural gas properties	(166,970)	(55,842)	(79,003)
Additions to oil and natural gas properties leasehold costs	(6,263)	(2,806)	(1,176)
Purchases of other property and equipment	(21)	(207)	(425)
Proceeds from the sale of oil and natural gas properties	9,009	11,102	198
Proceeds from farmouts of oil and natural gas properties	124,522	19,171	—
NET CASH USED IN INVESTING ACTIVITIES	(163,804)	(454,249)	(221,542)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from issuance of common units, net of offering costs	40,537	32,458	—
Proceeds from issuance of Series B cumulative convertible preferred units, net of offering costs	—	293,469	—
Distributions to common and subordinated unitholders	(250,121)	(194,799)	(175,943)
Distributions to Series A redeemable preferred unitholders	(690)	(3,777)	(6,385)
Distributions to Series B cumulative convertible preferred unitholders	(17,675)	—	—
Distributions to noncontrolling interests	(211)	(120)	(111)
Redemption of Series A redeemable preferred units	(2,115)	(19,704)	(18,461)
Repurchases of common and subordinated units	(10,579)	(8,185)	(27,436)
Purchase of noncontrolling interests	(1,706)	—	—
Borrowings under credit facility	373,500	292,500	349,000
Repayments under credit facility	(351,500)	(220,500)	(99,000)
Debt issuance costs and other	(1,242)	(3,075)	(239)
NET CASH (USED IN) PROVIDED BY FINANCING ACTIVITIES	(221,802)	168,267	21,425
NET CHANGE IN CASH AND CASH EQUIVALENTS	(228)	(4,130)	(3,461)
Cash and cash equivalents — beginning of the year	5,642	9,772	13,233
Cash and cash equivalents — end of the year	$ 5,414	$ 5,642	$ 9,772
SUPPLEMENTAL DISCLOSURE			
Interest paid	$ 19,761	$ 14,761	$ 6,535

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 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. On May 6, 2015, we completed our initial public offering (the "IPO") of 22,500,000 common units representing limited partner interests. 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").

The consolidated financial statements include the consolidated results of the Partnership, which also includes the results of the Noble Acquisition (as defined below) for the period from November 28, 2017 through December 31, 2018, as discussed in Note 4 – Oil and Natural Gas Properties Acquisitions.

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. Certain reclassifications have been made to the prior periods presented to conform to the current period financial statement presentation. The reclassifications have no effect on the consolidated financial position, results of operations, or cash flows of the Partnership.

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, 2018	December 31, 2017
	(in thousands)	
Accounts receivable:		
Revenues from contracts with customers	$ 107,804	$ 77,544
Other	5,344	3,151
Total accounts receivable	$ 113,148	$ 80,695

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 considered business combinations and are recorded at their estimated fair value as of the acquisition date. Acquisitions of unproved oil and natural gas properties are 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 we may also refer 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 quantities of oil and natural gas that can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, under existing economic conditions, operating methods, and government regulations. DD&A expense related to the Partnership's producing oil and natural gas properties was $122.5 million, $114.3 million, and $102.4 million for the years ended December 31, 2018, 2017, and 2016, 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 developed and proved undeveloped reserves, future commodity prices, timing of future production, future capital expenditures, and a risk-adjusted discount rate.

There was no impairment of proved oil and natural gas properties for the years ended December 31, 2018 and 2017. Impairment of proved oil and natural gas properties was $4.9 million for the year ended December 31, 2016. The impairment primarily resulted from declines in future expected realizable net cash flows. The charge is included in impairment of oil and natural gas properties on the consolidated statements of operations and reflected in the net book value of oil and natural gas properties.

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, 2018 and 2017. Impairment of unproved properties was $1.9 million for the year ended December 31, 2016, as included in impairment of oil and natural gas properties on the consolidated statements of operations and reflected in the net book value of oil and natural gas properties.

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 three to seven years. Depreciation and amortization expense totaled $0.2 million, $0.2 million, and $0.1 million for the years ended December 31, 2018, 2017, and 2016, 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,	
	2018	2017
Accrued liabilities:	(in thousands)	
Accrued capital expenditures	$ 32,945	$ 28,711
Accrued incentive compensation	16,109	16,503
Accrued property taxes	5,822	4,090
Accrued other	5,213	3,327
Total accrued liabilities	$ 60,089	$ 52,631

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 $0.9 million, $0.9 million, and $0.9 million for the years ended December 31, 2018, 2017, and 2016, 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.

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, we recognize 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.

Production imbalances

The Partnership previously elected to utilize the entitlements method to account for natural gas production imbalances, which is no longer permitted under ASC 606. As of January 1, 2018, these amounts were de minimis. As such, upon adoption of ASC 606, there was no material impact to the financial statements due to this change in accounting for the Partnership's production imbalances.

Allocation of transaction price to remaining performance obligations

Oil and natural gas sales

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

Lease bonus and other income

Given that the Partnership does not recognize lease bonus or other income until a lease agreement has been executed, at which point its performance obligation has been satisfied, and payment is received, the Partnership does not record revenue for unsatisfied or partially unsatisfied performance obligations as of the end of the reporting period. 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 U.S. 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 year ended December 31, 2018, 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, 2018 and 2017 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 or subordinated 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

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which supersedes the lease requirements in Topic 840, *Leases* by requiring lessees to recognize lease assets and lease liabilities classified as operating leases on the balance sheet. The new lease standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early adoption was permitted.

In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842), Targeted Improvements*, which allows entities to apply the transition provisions of the new standard at the adoption date instead of at the earliest comparative period presented in the consolidated financial statements, and also allows entities to continue to apply the legacy guidance in Topic 840, including disclosure requirements, in the comparative period presented in the year the new leases standard is adopted. Entities that elect this option would still adopt the new leases standard using a modified retrospective transition method, but would recognize a cumulative catch-up adjustment in the period of adoption rather than in the earliest period presented. The Partnership plans to use a modified retrospective transition method to apply the new standard to leases that exist as of the adoption date of January 1, 2019. The Partnership did not early adopt.

Based on evaluations to-date, the new guidance will not have a material impact on the Partnership's consolidated financial statements and related disclosures as this guidance does not apply to leases to explore for or use minerals, oil, natural gas, and similar resources.

In August 2018, the FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820)*, which will remove, modify, and add certain required disclosures on fair value measurements. As amended, Topic 820 will no longer require the disclosure of the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, the policy of timing of transfers between levels, and the valuation processes for Level 3 fair value measurements. In addition, certain modifications to current disclosure requirements will be made, including clarifying that the measurement uncertainty disclosure is to communicate information about the uncertainty in measurement as of the reporting date. Certain disclosure requirements will also be added, including the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. For certain unobservable inputs, an entity may disclose other quantitative information in place of the weighted average if the entity determines that other quantitative information would be a more reasonable and rational method to reflect the distribution of unobservable inputs used to develop Level 3 fair value measurements. The new standard will be effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. The Partnership does not plan to early adopt and is evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures.

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,	
	2018	2017
	(in thousands)	
Beginning asset retirement obligations	$ 14,509	$ 13,350
Liabilities incurred	245	308
Liabilities settled	(129)	(228)
Accretion expense	1,103	1,026
Revisions in estimated costs	(16)	83
Dispositions	(237)	(30)
Ending asset retirement obligations	$ 15,475	$ 14,509
Current asset retirement obligations	$ 527	$ 417
Non-current asset retirement obligations	$ 14,948	$ 14,092

NOTE 4 — OIL AND NATURAL GAS PROPERTIES ACQUISITIONS

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

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 included proved oil and natural gas properties were considered business combinations and 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 (as defined below) 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 which were considered business combinations:

	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 in unproved oil and natural gas properties from various sellers for an aggregate of $58.2 million. These acquisitions were considered asset acquisitions and 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.

Noble Acquisition

On November 28, 2017 (the "Close Date"), Black Stone Minerals Company, L.P. ("BSMC"), a wholly owned subsidiary of BSM, closed on the acquisition of (i) certain mineral interests and other non-cost bearing royalty interests from Noble Energy Inc., Noble Energy Wyco, LLC, and Rosetta Resources Operating LP and (ii) one hundred percent (100%) of the issued and outstanding securities of Samedan Royalty, LLC ("Samedan") from Noble Energy US Holdings, LLC, collectively, the "Noble Acquisition."

The mineral interests and other non-cost bearing royalty interests acquired in the Noble Acquisition, including interests owned by Samedan (the "Noble Assets") include approximately 1.1 million gross (140,000 net) mineral acres, 380,000 gross acres of non-participating royalty interests, and 600,000 gross acres of overriding royalty interests collectively spread over 20 states with significant concentrations in Texas, Oklahoma, and North Dakota.

The Partnership funded the $335 million purchase price (before customary post-closing adjustments) using (i) approximately $300 million in proceeds from its issuance of 14,711,219 Series B cumulative convertible preferred units to Mineral Royalties One, L.L.C., an affiliate of The Carlyle Group ("the Purchaser"), in a private placement which also closed on November 28, 2017, and (ii) approximately $35 million from borrowings under its Credit Facility. See additional discussion of the Series B cumulative convertible preferred units in Note 12 – Preferred Units.

The transaction was accounted for as a business combination using the acquisition method of accounting which requires, among other things, that the assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The final determination of fair value was completed in 2018 after post-closing purchase price adjustments were finalized. Since December 31, 2017, the Partnership has recorded an adjustment to the purchase price to reduce the amount allocated to unproved properties by $3.2 million, which reduces the Acquisitions of oil and natural gas properties line item of the consolidated statement of cash flows for the year ended December 31, 2018.

The following table summarizes the final allocation of the fair value of the assets acquired and the acquisition-related costs.

	Assets Acquired				Cash Consideration Paid[1]	Acquisition-Related Costs[2]
	Proved	Unproved	Net Working Capital	Total Fair Value		
	(in thousands)					
Noble Assets	$ 68,877	$ 256,542	$ 5,917	$ 331,336	$ 331,336	$ 247

[1] Represents cash consideration paid on the Close Date, as adjusted for the $3.2 million purchase price adjustment recorded during the year ended December 31, 2018.

[2] Acquisition-related costs were expensed and included in the general and administrative expense line item of the consolidated statement of operations for the year ended December 31, 2017.

The fair value of the Noble Assets was measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) oil and natural gas reserves; (ii) future commodity prices; (iii) estimated future cash flows; and (iv) market-based weighted average cost of capital. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change.

Actual and Pro Forma Impact of Noble Acquisition (Unaudited)

Revenue attributable to the Noble Acquisition included in the Partnership's consolidated statement of operations for the year ended December 31, 2017 was $2.8 million. The following table presents unaudited pro forma information for the Partnership as if the Noble Acquisition occurred on January 1, 2016.

	For the Year Ended December 31,	
	2017	2016
	(in thousands, except per unit amounts)	
Revenue and other income	$ 468,103	$ 288,772
Net income (loss)	$ 178,970	$ 33,264
Net income (loss) attributable to noncontrolling interests	34	12
Distributions on Series A redeemable preferred units	(3,117)	(5,763)
Distributions on Series B cumulative convertible preferred units	(21,000)	(21,000)
Net income (loss) attributable to the general partner and common and subordinated units	$ 154,887	$ 6,513
Allocation of net income (loss):		
General partner interest	—	—
Common units	99,776	20,696
Subordinated units	55,111	(14,183)
	$ 154,887	$ 6,513
Net income (loss) attributable to limited partners per common and subordinated unit:		
Per common unit (basic)	$ 1.02	$ 0.22
Per subordinated unit (basic)	$ 0.58	$ (0.15)
Per common unit (diluted)	$ 1.02	$ 0.22
Per subordinated unit (diluted)	$ 0.58	$ (0.15)

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Noble Acquisition and are factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the Partnership's consolidated results of operations would have been had the acquisition been completed on January 1, 2016. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations for the combined company. The unaudited pro forma consolidated results reflect the following pro forma adjustments:

- Adjustments to recognize incremental revenue, production costs and ad valorem taxes, and DD&A expense attributable to the Noble Assets.
- Adjustment to recognize additional interest expense associated with the incremental borrowings under the Partnership's Credit Facility.
- Adjustment to recognize the quarterly distribution associated with the issuance of 14,711,219 Series B cumulative convertible preferred units.
- The Series B cumulative convertible preferred units were excluded from the calculation of pro forma diluted earnings per common unit for the periods presented above due to their antidilutive effect under the if-converted method.
- The Series B cumulative convertible preferred units do not have any impact to earnings per subordinated unit.

2017 Acquisitions

In addition to the Noble Acquisition, the Partnership closed on multiple acquisitions of mineral and royalty interests, which also included producing properties, during the year ended December 31, 2017, as reflected in the table below. These acquisitions were primarily focused in the Delaware Basin and East Texas. The cash portion of all acquisitions below was funded via borrowings under the Partnership's Credit Facility.

	Assets Acquired				Consideration Paid		
	Proved	**Unproved**	**Net Working Capital**	**Total Fair Value**	**Cash**	**Fair Value of Common Units Issued**	**Acquisition-Related Costs**[1]
				(in thousands)			
January	$ 5,135	$ 34,008	$ 263	$ 39,406	$ 27,380	$ 12,026	$ 1,162
June	5,006	45,477	—	50,483	4,802	45,681	1,481
August	3,277	9,984	—	13,261	4,289	8,972	107
September	3,120	—	—	3,120	3,120	—	—
Total fair value	$ 16,538	$ 89,469	$ 263	$ 106,270	$ 39,591	$ 66,679	$ 2,750

[1] Acquisition-related costs were expensed and included in the general and administrative expense line item of the 2017 consolidated statement of operations.

In addition, the Partnership acquired mineral and royalty interests from various sellers in East Texas as reflected in the table below. The cash portion of all acquisitions below was funded via borrowings under the Partnership's Credit Facility.

	Assets Acquired	Consideration Paid	
	Unproved	**Cash**	**Fair Value of Common Units Issued**
		(in thousands)	
Q1 2017	$ 21,189	$ 21,017	$ 172
Q2 2017	13,329	13,329	—
Q3 2017	19,946	15,205	4,741
Q4 2017	2,267	2,137	130
Total acquired	$ 56,731	$ 51,688	$ 5,043

Farmout Agreements

On February 21, 2017, the Partnership announced that it had 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., a subsidiary of Exxon Mobil Corporation. The Partnership has an approximate 50% working interest in the acreage and is the largest mineral owner. A total of 18 wells were drilled over an initial phase, beginning with wells spud after January 1, 2017. Canaan has elected to participate in an additional phase with each phase continuing for the lesser of 2 years or until 20 wells have been drilled. After the completion of the second phase, Canaan will have the option to elect for a similar third phase. During the first three phases of the 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 will receive an overriding royalty interest (“ORRI”) before payout and an increased ORRI after payout on all wells drilled under the agreement. From the inception of the agreement through December 31, 2018, the Partnership has received $80.7 million from Canaan under the agreement. As of December 31, 2018, the Partnership had assigned to Canaan working interests in certain wells drilled and completed, and as such, only $11.6 million is included in the Other long-term liabilities line item of the consolidated balance sheet.

On November 21, 2017, the Partnership entered into a farmout agreement 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 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. In wells operated by XTO Energy Inc. in San

Augustine County, Texas, Pivotal will earn the Partnership's remaining working interest not covered by the Canaan Farmout (10% working interest on an 8/8th basis), as well as 100% of the Partnership's working interests (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells operated by its other major operator in San Augustine and Angelina counties, Texas. Initially, Pivotal is obligated to fund the development of up to 80 wells 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. Pivotal will fund designated groups of wells. 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. From the inception of the agreement through December 31, 2018, the Partnership received $63.0 million from Pivotal under the agreement. As of December 31, 2018, the Partnership had assigned to Pivotal working interests in certain wells drilled and completed, and as such, only $41.2 million is included in the Other long-term liabilities line item of the consolidated balance sheet.

As of December 31, 2017, all amounts received from Canaan and Pivotal under the agreements were included in the Other long-term liabilities line item of the consolidated balance sheet, as no working interest had been assigned to Canaan or Pivotal as of that date.

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, 2018, 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, 2018 and 2017. 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. 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, 2018, the Partnership had ten counterparties, all of which are rated Baa1 or better by Moody’s. Nine of the Partnership's counterparties are lenders under the Partnership's Credit Facility. The Partnership would have been at risk of losing a fair value amount of $50.3 million had the Partnership's counterparties as a group been unable to fulfill their obligations as of December 31, 2018.

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 at December 31, 2018 and 2017:

		As of December 31, 2018		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 38,746	$ (776)	$ 37,970
Long-term asset	Deferred charges and other long-term assets	11,518	(1,450)	10,068
Total assets		$ 50,264	$ (2,226)	$ 48,038
Liabilities:				
Current liability	Commodity derivative liabilities	$ 776	$ (776)	$ —
Long-term liability	Commodity derivative liabilities	1,450	(1,450)	—
Total liabilities		$ 2,226	$ (2,226)	$ —

		As of December 31, 2017		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 10,713	$ (10,619)	$ 94
Long-term asset	Deferred charges and other long-term assets	1,392	(1,029)	363
Total assets		$ 12,105	$ (11,648)	$ 457
Liabilities:				
Current liability	Commodity derivative liabilities	$ 14,841	$ (10,619)	$ 4,222
Long-term liability	Commodity derivative liabilities	2,292	(1,029)	1,263
Total liabilities		$ 17,133	$ (11,648)	$ 5,485

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 consisted of the following for the periods presented:

	For the year ended December 31,		
Derivatives not designated as hedging instruments	**2018**	**2017**	**2016**
		(in thousands)	
Beginning fair value of commodity derivative instruments	$ (5,028)	$ (16,719)	$ 64,534
Gain (loss) on oil derivative instruments	24,300	(5,091)	(15,998)
Gain (loss) on natural gas derivative instruments	(9,469)	31,993	(20,466)
Net cash paid (received) on settlements of oil derivative instruments	34,905	(10,901)	(27,450)
Net cash paid (received) on settlements of natural gas derivative instruments	3,330	(4,310)	(17,339)
Net change in fair value of commodity derivative instruments	53,066	11,691	(81,253)
Ending fair value of commodity derivative instruments	$ 48,038	$ (5,028)	$ (16,719)

The Partnership had the following open derivative contracts for oil as of December 31, 2018:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (per Bbl)	Range (per Bbl) Low	Range (per Bbl) High
Oil Swap Contracts:				
2018				
Fourth quarter	285,000	$ 55.18	$ 52.09	$ 61.88
2019				
First quarter	645,000	$ 58.66	$ 52.82	$ 65.58
Second quarter	645,000	58.66	52.82	65.58
Third quarter	645,000	58.20	52.82	63.75
Fourth quarter	645,000	58.20	52.82	63.75

Period and Type of Contract	Volume (Bbl)	Weighted Average Floor Price (Per Bbl)	Weighted Average Ceiling Price (Per Bbl)
Oil Collar Contracts:			
2019			
First quarter	60,000	$ 65.00	$ 74.00
Second quarter	60,000	65.00	74.00
Third quarter	60,000	65.00	74.00
Fourth quarter	60,000	65.00	74.00
2020			
First quarter	210,000	$ 56.43	$ 67.14
Second quarter	210,000	56.43	67.14
Third quarter	210,000	56.43	67.14
Fourth quarter	210,000	56.43	67.14

The Partnership had the following open derivative contracts for natural gas as of December 31, 2018:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (per MMBtu)	Range (per MMBtu) Low	Range (per MMBtu) High
Natural Gas Swap Contracts:				
2019				
First quarter	14,400,000	$ 2.96	$ 2.81	$ 3.20
Second quarter	14,520,000	2.96	2.81	3.20
Third quarter	14,640,000	2.96	2.81	3.20
Fourth quarter	14,640,000	2.96	2.81	3.20

The Partnership entered into the following derivative contracts for oil subsequent to December 31, 2018:

Period and Type of Contract	Volume (Bbl)	Weighted Average (Per Bbl)	Range (Per Bbl) Low	Range (Per Bbl) High
Oil Swap Contracts:				
2019				
First quarter	40,000	$ 57.88	$ 57.88	$ 57.88
Second quarter	120,000	57.88	57.88	57.88
Third quarter	120,000	57.88	57.88	57.88
Fourth quarter	120,000	57.88	57.88	57.88
2020				
First quarter	180,000	$ 57.48	$ 57.46	$ 57.50
Second quarter	180,000	57.48	57.46	57.50
Third quarter	180,000	57.48	57.46	57.50
Fourth quarter	180,000	57.48	57.46	57.50

The Partnership entered into the following derivative contracts for natural gas subsequent to December 31, 2018:

Period and Type of Contract	Volume (MMbtu)	Weighted Average (Per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2020				
First quarter	6,370,000	$ 2.72	$ 2.72	$ 2.73
Second quarter	6,370,000	2.72	2.72	2.73
Third quarter	6,440,000	2.72	2.72	2.73
Fourth quarter	6,440,000	2.72	2.72	2.73

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, 2018 and 2017.

The carrying value of our 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, 2018 and 2017 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, 2018					
Financial Assets					
Commodity derivative instruments	$ —	$ 50,264	$ —	$ (2,226)	$ 48,038
Financial Liabilities					
Commodity derivative instruments	—	2,226	—	(2,226)	—
As of December 31, 2017					
Financial Assets					
Commodity derivative instruments	$ —	$ 12,105	$ —	$ (11,648)	$ 457
Financial Liabilities					
Commodity derivative instruments	—	17,133	—	(11,648)	5,485

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, 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 Acquisitions.

Oil and natural gas properties are measured at fair value on a nonrecurring basis using the income approach when assessing for impairment. Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties. When assessing producing properties for impairment, the Partnership compares the expected undiscounted projected future cash flows of the producing properties to the carrying amount of the producing properties to determine recoverability. When the carrying amount exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, future capital expenditures, and a risk-adjusted discount rate.

The Partnership's estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no significant changes in valuation techniques or related inputs for the years ended December 31, 2018 and 2017.

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

	Fair Value Measurements Using			Net Book	
	Level 1	Level 2	Level 3[1]	Value[1]	Impairment
			(In thousands)		
Year Ended December 31, 2018					
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —	$ —
Year Ended December 31, 2017					
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —	$ —
Year Ended December 31, 2016					
Impaired oil and natural gas properties	$ —	$ —	$ 3,042	$ 9,817	$ 6,775

[1] Amounts represent fair value and net book value at the date of assessment.

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 Inc. represented approximately 15%, 21%, and 11% of total revenue for the years ended December 31, 2018, 2017, and 2016.

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 a maximum credit amount of $1.0 billion. The amount of the borrowing base is derived from the value of the Partnership's oil and natural gas properties determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices.

Drawings on the Credit Facility are used for the acquisition of oil and natural gas properties and for other general business purposes. Effective October 31, 2016 the borrowing base was $500.0 million and, effective April 25, 2017, the borrowing base redetermination resulted in an increase to $550.0 million. On November 1, 2017, the Partnership amended and restated the credit agreement to extend the maturity thereof for a term of five years, create a swingline facility that permits short-term borrowings on same-day notice, and make other changes to the hedging and restrictive covenants. There was no change to the borrowing base. The Credit Facility now terminates on November 1, 2022. Effective May 4, 2018, the borrowing base redetermination resulted in an increase to $600.0 million and, effective October 31, 2018, the borrowing base was further increased to $675.0 million.

Effective October 31, 2016, borrowings under the Credit Facility bore interest at LIBOR plus a margin between 2.00% and 3.00%, or the Prime Rate plus a margin between 1.00% and 2.00%, with the margin depending on the borrowing base utilization of the loan. Effective October 31, 2018, the LIBOR margin was reduced to between 1.75% and 2.75% and the Prime Rate margin was reduced to between 0.75% and 1.75%.

The weighted-average interest rate of the Credit Facility was 4.76% and 4.06% as of December 31, 2018 and 2017, 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, 2018, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $410.0 million and $388.0 million at December 31, 2018 and 2017, respectively. The unused portion of the available borrowings under the Credit Facility were $265.0 million and $162.0 million at December 31, 2018 and 2017, respectively.

NOTE 9 — INCENTIVE COMPENSATION

Overview

The Board of the Partnership’s general partner 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 and subordinated 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 the common and subordinated 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. Certain employees are entitled to receive cash bonuses based on service criteria over a four-year requisite service period ending in 2019. 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 and extends 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. 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.

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 through March 15, 2019. The holders of restricted common unit awards have all the rights of a common unitholder, including non-forfeitable distribution rights with respect to their restricted common units. The grant-date fair value of these awards, net of estimated forfeitures, is recognized ratably using the straight-line attribution method.

The Compensation Committee of the Board (the "Compensation Committee") annually approves a grant of awards to each of the executive officers of the Partnership's general partner and certain other employees. Consistent with previous awards the 2018 grant includes restricted common units subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through January 7, 2021. Holders of restricted common unit awards have all the rights of a common unitholder, including non-forfeitable distribution rights with respect to their restricted common units. The grant-date fair value of these awards, net of estimated forfeitures, is recognized ratably using the straight-line attribution method.

The following table summarizes information about restricted units for the year ended December 31, 2018.

	Units		Weighted-Average Grant-Date Fair Value per Unit	
	Common	Subordinated	Common	Subordinated
Unvested at December 31, 2017	1,542,058	59,129	$ 16.72	$ 18.30
Granted	462,512	—	17.95	—
Vested	(669,728)	(59,129)	16.43	18.30
Converted	—	—	—	—
Forfeited	(826)	—	17.87	—
Unvested at December 31, 2018	1,334,016	—	17.29	—

The weighted-average grant-date fair value per unit for unit-based awards was $17.95, $18.48, and $10.09 for the years ended December 31, 2018, 2017, and 2016, respectively. As of December 31, 2018, unrecognized compensation cost associated with restricted common unit awards was $11.0 million, which the Partnership expects to recognize over a weighted-average period of 1.47 years. As of December 31, 2018, there was no unrecognized compensation cost associated with restricted subordinated unit awards. The fair value of units vested for the years ended December 31, 2018, 2017, and 2016 was $12.9 million, $25.1 million, and $11.9 million, respectively. There were no cash payments made for vested units during the years ended December 31, 2018, 2017 and 2016.

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, 2018.

Performance units	Number of Units	Weighted-Average Grant-Date Fair Value per Unit
Unvested at December 31, 2017	1,457,356	$ 15.51
Granted	463,251	17.94
Vested	(91,757)	18.78
Forfeited	(17,040)	18.94
Unvested at December 31, 2018	1,811,810	15.94

The weighted-average grant-date fair value per unit for performance unit awards awards was $17.94, $17.99, and $11.36 for the years ended December 31, 2018, 2017, and 2016, respectively. Unrecognized compensation cost associated with performance unit awards was $8.4 million as of December 31, 2018, which the Partnership expects to recognize over a weighted-average period of 1.55 years. The fair value of performance units vested for the years ended December 31, 2018, and 2016 was $1.5 million, and $3.2 million, respectively. No performance units vested for the year ended December 31, 2017.

Incentive Compensation

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, 2018, 2017, and 2016.

	Year Ended December 31,		
Incentive compensation expense	2018	2017	2016
	(In thousands)		
Cash — short and long-term incentive plan	$ 9,301	$ 4,373	$ 7,414
Equity-based compensation — restricted common and subordinated units	13,624	13,476	13,408
Equity-based compensation — restricted performance units	14,188	17,367	18,518
Board of Directors incentive plan	2,322	2,202	2,012
Total incentive compensation expense	$ 39,435	$ 37,418	$ 41,352

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 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 $0.7 million, $0.6 million, and $0.5 million for the years ended December 31, 2018, 2017, and 2016, respectively.

NOTE 11 — COMMITMENTS AND CONTINGENCIES

Leases

The Partnership leases certain office space and equipment under cancelable and non-cancelable operating leases that end at various dates through 2023. The Partnership recognizes rent expense on a straight-line basis over the lease term. Rent expense under such arrangements was $2.2 million, $2.5 million, and $1.9 million for the years ended December 31, 2018, 2017, and 2016, respectively. Such amounts are included in general and administrative expense on the consolidated statements of operations.

Future minimum lease commitments under non-cancelable leases are as follows as of December 31, 2018:

Year Ending December 31,		(in thousands)
2019	$	1,386
2020		1,371
2021		1,385
2022		1,411
2023		1,439
Total	$	6,992

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.

Put Option Related to Noble Acquisition

By acquiring 100% of the issued and outstanding securities of Samedan, now NAMP Holdings, LLC, on November 28, 2017 as part of the Noble Acquisition, the Partnership acquired a 100% interest in Comin-Termin, LLC, now NAMP GP, LLC ("Holdings"), Comin 1989 Partnership LLLP, now NAMP 1, LP ("Comin"), and Temin 1987 Partnership LLLP, now NAMP 2, LP ("Temin"). Pursuant to certain co-ownership agreements, various co-owners hold undivided beneficial ownership interests in 54.67% and 57.37% of the mineral interests held of record by Holdings and Temin, respectively. Based on the terms of the co-ownership agreements, the co-owners each have an unconditional option to require Comin or Temin, as applicable, to purchase their beneficial ownership interest in the mineral interests held of record by Holdings or Temin, as applicable, at any time within 30 days of receiving such repurchase notice. The purchase price of the beneficial ownership interest shall be based on an evaluation performed by Comin or Temin, as applicable, in good faith. As of December 31, 2018, the Partnership had not received notice from any co-owner to exercise their repurchase option, and as such, no liability was recorded.

Pipeline Extension Agreement

On May 30, 2018, the Partnership and a development partner entered into an agreement authorizing the Partnership's pipeline transportation service provider, in the development area, to construct an extension to its existing gathering system ("Pipeline Extension") for an estimated cost of $8.7 million. The Partnership and its development partner will each have 50% of the firm capacity to flow natural gas through the Pipeline Extension. Once the facilities are ready for service, the cost of the project will be recovered through an incremental gathering fee that will be charged on a per Mcf basis of natural gas that flows through the Pipeline Extension. When the service provider has been fully reimbursed for the project, the incremental gathering fees will no longer be charged. If the cost of the Pipeline Extension is not recovered through these fees within four years of the initial flow, the Partnership will be required to pay its share (50%) of the costs that were not recovered. As of December 31, 2018, the Partnership expects the cost of the Pipeline Extension to be recovered through incremental gathering fees, and as such, no liability was 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, 2018 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, 2018, there were no Series A redeemable preferred units outstanding, while as of December 31, 2017 there were 26,363 Series A redeemable preferred units outstanding with a carrying value of $27.0 million. The carrying value included accrued distributions of $0.7 million. The Series A redeemable preferred units are classified as mezzanine equity on the consolidated balance sheets since redemption was outside the control of the Partnership. The Series A redeemable preferred units were entitled to an annual distribution of 10%, payable on a quarterly basis in arrears.

Prior to liquidation of the Partnership, and while any of the Series A redeemable preferred units remained outstanding, cash or other property of the Partnership were distributed 100% to the Series A redeemable preferred unitholders until the aggregate Unpaid Preferred Yield (as defined below) of each Series A redeemable preferred unit accrued through the last day of the immediately preceding calendar quarter had been reduced to zero. Distributions in excess of the aggregate Unpaid Preferred Yield were distributed 100% to common and subordinated unitholders, until there had been distributed an aggregate amount in respect of such calendar year equal to 10% of the aggregate Interest Fair Market Value of the outstanding common and subordinated units as of the first day of such calendar year. Any additional distributions were distributed to the common and subordinated unitholders, on the one hand, and the Series A redeemable preferred unitholders, on the other hand, pro rata on an as-is-converted basis.

The terms “Interest Fair Market Value,” “Preferred Yield,” and “Unpaid Preferred Yield” have the following meanings:

“Interest Fair Market Value” means, as of any date, the amount which would be received by the holder of a common unit or subordinated unit, as applicable, if (a) all of the Series A redeemable preferred units were converted into or exchanged or exercised for common units and, during the subordination period, subordinated units, (b) the fair market value of the assets of the Partnership in excess of its liabilities as of the date of determination of Interest Fair Market Value equaled the Value (as defined in the partnership agreement) as of such date, adjusted to reflect any increases in equity value resulting from the deemed conversion, exchange or exercise of convertible securities, and (c) an amount equal to such Value (as defined in the partnership agreement), as so adjusted, were distributed to the unitholders in accordance with the liquidation distribution provisions of the partnership agreement.

“Preferred Yield” means a yield on the outstanding Series A redeemable preferred units equivalent to a 10% per annum interest rate (subject to adjustment following certain events of default by the Partnership) on an initial investment of $1,000, calculated based on a 365-day year and compounded quarterly.

“Unpaid Preferred Yield” means, with respect to each Series A redeemable preferred unit and as of any date of determination, an amount equal to the excess, if any, of (a) the cumulative Preferred Yield from the closing of the IPO through the date established, over (b) the cumulative amount of distributions made as of the date established in respect of the Series A redeemable preferred unit.

The Series A redeemable preferred units were convertible into common and subordinated units 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 Partnership had the right, at its sole option, to redeem an amount of Series A redeemable preferred units equal to the units being redeemed by an owner of Series A redeemable preferred units on each December 31. Any amount of a given year’s Series A redeemable preferred units eligible for redemption not redeemed on December 31 were automatically converted to common and subordinated units on January 1 in the following year. 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. For the year ended December 31, 2018, 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.

For the year ended December 31, 2017, 19,704 Series A redeemable preferred units were redeemed for $20.2 million, including accrued unpaid yield. For the year ended December 31, 2017, 6,624 Series A redeemable preferred units totaling $6.6

million were converted into 200,996 common units and 263,247 subordinated units as a result of the mandatory conversion subsequent to December 31, 2016.

For the year ended December 31, 2016, 18,461 Series A redeemable preferred units were redeemed for $19.0 million, including accrued unpaid yield. For the year ended December 31, 2016, 6,064 Series A redeemable preferred units totaling $6.1 million were converted into the equivalent of 184,006 common units and 240,986 subordinated units on an adjusted basis as a result of the mandatory conversion subsequent to December 31, 2015.

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 are convertible into common units of the Partnership on November 29, 2019 and once per quarter thereafter. At such time, 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 and $295.4 million, including accrued distributions of $5.3 million and $1.9 million, as of December 31, 2018 and 2017. The Series B cumulative convertible preferred units are classified as mezzanine equity on the consolidated balance sheet 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 and subordinated units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common and subordinated 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 our 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.

For the purpose of calculating diluted EPU, the Series A redeemable preferred units could be converted into 0.2 million weighted average common units and 0.2 million weighted average subordinated units for the year ended December 31, 2018, 0.8 million weighted average common units and 1.1 million weighted average subordinated units for the year ended December 31, 2017, and 1.6 million weighted average common units and 2.1 million weighted average subordinated units for the year ended December 31, 2016. For the year ended December 31, 2018, if the outstanding Series A redeemable preferred units were converted to common and subordinated units as of the beginning of the period, the effect would be anti-dilutive to common unitholders. Therefore, the Series A redeemable preferred units are not included in the diluted EPU calculations for common units for the year ended December 31, 2018. For the years December 31, 2017 and 2016, if the outstanding Series A redeemable preferred units were converted to common and subordinated units as of the beginning of each period, the effect would be anti-dilutive. Therefore, the Series A redeemable preferred units are not included in the diluted EPU calculations for the years ended December 31, 2017 and 2016.

For the purpose of calculating diluted EPU, the Series B cumulative convertible preferred units could be converted into 15.0 million and 1.6 million weighted average common units for the years ended December 31, 2018 and 2017, respectively. For the year ended December 31, 2017, if the outstanding Series B cumulative convertible preferred units were converted to common units as of the beginning of the period, the effect would be anti-dilutive. Therefore, the Series B cumulative convertible preferred units are not included in the diluted EPU calculations for the year ended December 31, 2017.

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. For the year ended December 31, 2018, there were an additional 0.2 million weighted average common units related to the Partnership's restricted performance unit awards included in the calculation of diluted EPU.

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

	For the Year Ended December 31,		
	2018	2017	2016
	(in thousands, except per unit amounts)		
NET INCOME (LOSS)	$ 295,560	$ 157,153	$ 20,188
Net (income) loss attributable to noncontrolling interests	(24)	34	12
Distributions on Series A redeemable preferred units	(25)	(3,117)	(5,763)
Distributions on Series B cumulative convertible preferred units	(21,000)	(1,925)	—
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	$ 274,511	$ 152,145	$ 14,437
ALLOCATION OF NET INCOME (LOSS):			
General partner interest	$ —	$ —	$ —
Common units	154,662	98,389	24,669
Subordinated units	119,849	53,756	(10,232)
	$ 274,511	$ 152,145	$ 14,437
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:			
Per common unit (basic)	$ 1.46	$ 1.01	$ 0.26
Weighted average common units outstanding (basic)	106,064	97,400	96,073
Per subordinated unit (basic)	$ 1.25	$ 0.56	$ (0.11)
Weighted average subordinated units outstanding (basic)	96,099	95,149	95,138
Per common unit (diluted)[1]	$ 1.45	$ 1.01	$ 0.26
Weighted average common units outstanding (diluted)	121,264	97,400	96,243
Per subordinated unit (diluted)[2]	$ 1.25	$ 0.56	$ (0.11)
Weighted average subordinated units outstanding (diluted)	96,346	95,149	95,138

[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 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.

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 BSMC prior to the IPO, their transferees, persons who acquired such units with the prior approval of the board of directors of the Partnership's general partner, 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 and subordinated units are entitled to participate in distributions and exercise the rights and privileges provided to limited partners holding common units and subordinated units under the partnership agreement.

The partnership agreement generally provides that any distributions will be paid each quarter during the subordination period (as defined in our partnership agreement) 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;
- *second*, to the holders of common units, until each common unit has received the applicable minimum quarterly distribution plus any arrearages from prior quarters; and
- *third*, to the holders of subordinated units, until each subordinated unit has received the applicable minimum quarterly distribution.

The priority right of the common unit holders will cease to exist upon full conversion of the subordinated units to common units, which may occur as early as May of 2019. If the distributions to common and subordinated unitholders exceed the applicable minimum quarterly distribution per unit, then such excess amounts will be distributed pro rata on the common and subordinated units as if they were a single class.

The following table provides information about our per share distributions to common and subordinated unitholders:

	Year Ended December 31,		
	2018	2017	2016
DISTRIBUTIONS DECLARED AND PAID:			
Per common unit	$ 1.33	$ 1.20	$ 1.10
Per subordinated unit	$ 1.13	$ 0.79	$ 0.74

Common Unit Repurchase Program

On November 5, 2018, the Board of the Partnership's general partner 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. In 2018, the Partnership repurchased a total of 128,627 common units for an aggregate cost of $2.0 million. The repurchase program is funded from the Partnership's cash on hand or availability on the Credit Facility. Any repurchased units are canceled.

On March 4, 2016, the Board of the Partnership's general partner authorized the repurchase of up to $50.0 million in common units through a program that terminated on September 15, 2016. The repurchase program authorized 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. In 2016, the Partnership repurchased a total of 1,315,574 common units for an aggregate cost of $20.2 million. The repurchase program was funded from the Partnership's cash on hand or availability on the Credit Facility.

NOTE 15 — 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.

Common units to be sold pursuant to the Equity Distribution Agreement will be offered and sold pursuant to the Partnership's existing effective shelf-registration statement on Form S-3 (File No. 333-215857), which was declared effective by the Securities and Exchange Commission on February 8, 2017.

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, 2018, the Partnership sold 2,243,775 common units under the ATM Program for net proceeds of $40.5 million. For the year ended December 31, 2017, the Partnership sold 2,001,823 common units under the ATM Program for net proceeds of $32.5 million.

NOTE 16 — SUBSEQUENT EVENTS

On February 7, 2019, the Board approved a distribution for the period from October 1, 2018 to December 31, 2018 of $0.37 per common unit and $0.37 per subordinated unit. Distributions were paid on February 26, 2019 to unitholders of record at the close of business on February 19, 2019.

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,		
	2018	2017	2016
	(in thousands)		
Acquisition Costs of Properties:[1]			
Proved	$ 13,438	$ 96,596	$ 40,242
Unproved	136,079	383,535	100,888
Exploration Costs	13,544	618	645
Development Costs[1]	165,198	81,056	73,316
Total	$ 328,259	$ 561,805	$ 215,091

1 See Note 4 – Oil and Natural Gas Properties Acquisitions for further discussion. Unproved properties include purchases of leasehold prospects. Development costs include costs incurred on farmout wells subject to reimbursement under our 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,	
	2018	2017
	(in thousands)	
Proved properties[1]	$ 2,377,305	$ 2,258,893
Unproved properties	1,063,883	988,720
Total	3,441,188	3,247,613
Accumulated depreciation, depletion, amortization, and impairment	(1,865,692)	(1,766,842)
Oil and natural gas properties, net	$ 1,575,496	$ 1,480,771

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. These reserve estimates exclude insignificant natural gas liquid quantities owned by the Partnership. 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.

	Crude Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)
Net proved reserves at December 31, 2015	15,842	203,675	49,788
Revisions of previous estimates[1, 9]	2,097	23,106	5,948
Purchases of minerals in place[2, 9]	1,520	6,717	2,639
Extensions, discoveries and other additions[3, 9]	2,589	84,339	16,646
Production	(3,680)	(47,498)	(11,596)
Net proved reserves at December 31, 2016	18,368	270,339	63,425
Revisions of previous estimates [1, 9]	(2,298)	14,505	120
Purchases of minerals in place [4,9]	2,335	31,323	7,555
Extensions, discoveries and other additions[5, 9]	3,046	43,886	10,360
Production	(3,552)	(59,779)	(13,515)
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[6]	227	419	297
Extensions, discoveries and other additions[5]	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
Net Proved Developed Reserves[7]			
December 31, 2016	18,150	223,057	55,327
December 31, 2017	17,891	233,017	56,727
December 31, 2018	17,567	278,233	63,939
Net Proved Undeveloped Reserves[8]			
December 31, 2016	218	47,282	8,098
December 31, 2017	8	67,257	11,218
December 31, 2018	—	35,787	5,965

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

[2] Includes the acquisition of mineral and royalty reserves primarily in the Marcellus and Wolfcamp plays.

[3] Includes discoveries and additions primarily related to active drilling in the Haynesville/Bossier, Bakken/Three Forks, Wilcox, Eagle Ford, and Fayetteville plays.

[4] Includes the acquisition of mineral and royalty reserves primarily in East Texas and the Permian and Williston basins.

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

[6] Includes the acquisition of mineral and royalty reserves primarily in the Wolfcamp play and East Texas.

[7] As of December 31, 2018, no proved developed reserves were attributable to noncontrolling interests in the Partnership's consolidated subsidiaries. Proved developed reserves of 61 MBoe and 74 MBoe as of December 31, 2017 and 2016, respectively, were attributable to noncontrolling interests.

[8] As of December 31, 2018, 2017, and 2016, no proved undeveloped reserves were attributable to noncontrolling interests.

[9] Due to the Noble Acquisition in November 2017 and increased drilling activity on our mineral acreage in 2018, we modified our methodology for computing the sources of changes in proved reserves. The change in methodology is to classify current

period production from new wells as extensions, discoveries and other additions and to classify current period production from new acquisitions as purchases of minerals in place. These items were previously classified as revisions of previous estimates. We changed the presentation of 2017 and 2016 to be consistent with our 2018 presentation. We believe the change in methodology is a more accurate reflection of the changes in our reserves although the impact to the previous years presentation was not material.

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,		
	2018	2017	2016
	(in thousands)		
Future cash inflows	$ 2,038,508	$ 1,643,582	$ 1,267,179
Future production costs	(222,342)	(211,064)	(193,749)
Future development costs	(58,403)	(70,111)	(36,509)
Future income tax expense	(6,333)	(2,655)	(3,516)
Future net cash flows (undiscounted)	1,751,430	1,359,752	1,033,405
Annual discount 10% for estimated timing	(663,814)	(497,103)	(430,390)
Total[1]	$ 1,087,616	$ 862,649	$ 603,015

[1] Includes standardized measure of discounted future net cash flows of approximately $0.5 million and $0.6 million for December 31, 2017 and 2016 attributable to noncontrolling interests in the Partnership's consolidated subsidiaries.

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

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Standardized measure, beginning of year	$ 862,649	$ 603,015	$ 554,972
Sales, net of production costs	(475,742)	(295,941)	(210,354)
Net changes in prices and production costs related to future production[1]	275,091	161,221	(80,721)
Extensions, discoveries and improved recovery, net of future production and development costs[1]	370,695	166,616	139,407
Previously estimated development costs incurred during the period	14,509	11,118	28,909
Revisions of estimated future development costs[1]	(558)	2,653	(2,380)
Revisions of previous quantity estimates, net of related costs[1]	(5,401)	60,476	57,577
Accretion of discount	86,441	60,512	55,662
Purchases of reserves in place, less related costs[1]	8,975	113,342	42,940
Changes in timing and other[1]	(49,043)	(20,363)	17,003
Net increase (decrease) in standardized measures	224,967	259,634	48,043
Standardized measure, end of year	$ 1,087,616	$ 862,649	$ 603,015

[1] Due to the Noble Acquisition in November 2017 and increased drilling activity on our mineral acreage in 2018, we modified our methodology for computing the principal sources of changes in the standardized measure. The change in methodology is

to classify current period production from new wells as extensions, discoveries and improved recovery and to classify current period production from new acquisitions as purchases of reserves in place. These items were previously classified as revisions of previous quantity estimates. We changed the presentation of 2017 and 2016 to be consistent with our 2018 presentation. We believe the change in methodology is a more accurate reflection of the principal sources of changes in the standardized measure although the impact to the previous years presentation was not material.

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)			
2018				
Total revenue	$ 114,494	$ 109,309	$ 139,718	$ 246,047
Income (loss) from operations	47,960	33,524	66,180	170,717
Net income (loss)	41,957	28,690	60,775	164,138
Net income (loss) attributable to the general partner and common and subordinated units	36,655	23,488	55,503	158,865
Net income (loss) attributable to common and subordinated units per unit (basic)[1]				
Per common unit (basic)	0.23	0.17	0.27	0.78
Per subordinated unit (basic)	0.13	0.06	0.27	0.78
Net income (loss) attributable to common and subordinated units per unit (diluted)[1]				
Per common unit (diluted)	0.23	0.17	0.27	0.72
Per subordinated unit (diluted)	0.13	0.06	0.27	0.78
Cash distributions declared and paid per limited partner unit				
Per common unit	$ 0.3125	$ 0.3125	$ 0.3375	$ 0.3700
Per subordinated unit	$ 0.2088	$ 0.2087	$ 0.3375	$ 0.3700
Total assets	$ 1,635,978	$ 1,669,464	$ 1,754,259	$ 1,750,124
Long-term debt	436,000	421,000	402,000	410,000
Total mezzanine equity	300,644	298,361	298,361	298,361
2017				
Total revenue	$ 124,582	$ 120,524	$ 89,111	$ 95,442
Income (loss) from operations	65,015	57,840	26,216	23,013
Net income (loss)	61,583	54,174	22,034	19,362
Net income (loss) attributable to the general partner and common and subordinated units	60,460	53,518	21,388	16,779
Net income (loss) attributable to common and subordinated units per unit (basic)[1]				
Per common unit (basic)	0.37	0.33	0.16	0.15
Per subordinated unit (basic)	0.26	0.22	0.05	0.03
Net income (loss) attributable to common and subordinated units per unit (diluted)[1]				
Per common unit (diluted)	0.37	0.33	0.16	0.15
Per subordinated unit (diluted)	0.26	0.22	0.05	0.03
Cash distributions declared and paid per limited partner unit				
Per common unit	$ 0.2875	$ 0.2875	$ 0.3125	$ 0.3125
Per subordinated unit	$ 0.1838	$ 0.1838	$ 0.2088	$ 0.2088
Total assets	$ 1,199,722	$ 1,250,086	$ 1,246,070	$ 1,576,451
Long-term debt	388,000	393,000	362,000	388,000
Total mezzanine equity	34,145	27,085	27,092	322,422

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

SUBSIDIARIES OF BLACK STONE MINERALS, L.P.

Entity	Jurisdiction of Organization
Black Stone Energy Company, L.L.C.	Texas
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. 333-211426) of Black Stone Minerals, L.P., and

(3) Registration Statement (Form S-3 No. 333-215857) of Black Stone Minerals, L.P.;

of our reports dated February 26, 2019, 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, 2018.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2019

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, 2018, and the inclusion of our corresponding report letter, dated January 17, 2019, in the 2018 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/ J. Carter Henson, Jr.

J. Carter Henson, Jr., P.E.
Senior Vice President

Houston, Texas
February 26, 2019

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 26, 2019

/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, Jeff 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 26, 2019

/s/ Jeff Wood

Jeff 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 26, 2019	/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 26, 2019	/s/ Jeff Wood
		Jeff Wood President and Chief Financial Officer Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.

January 17, 2019

Mr. Brock E. Morris
Black Stone Minerals, L.P.
1001 Fannin, Suite 2020
Houston, Texas 77002

Dear Mr. Morris:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2018, 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, 2018, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	17,413.8	254,791.3	1,591,211.8	988,699.7
Proved Developed Non-Producing	153.2	23,441.1	72,044.0	41,743.9
Proved Undeveloped	0.0	35,787.5	94,507.1	61,131.8
Total Proved	17,567.0	314,019.8	1,757,763.0	1,091,575.5

Totals may not add because of rounding.

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

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

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

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2018. For oil volumes, the average West Texas Intermediate spot price of $65.56 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.100 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 $62.81 per barrel of oil and $2.978 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. J. Carter Henson, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1989 and has over 8 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/ J. Carter Henson, Jr.
J. Carter Henson, Jr., P.E. 73964
Senior Vice President

Date Signed: January 17, 2019

JCH: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.

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

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

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

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

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

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

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

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

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

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

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

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

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

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

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

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

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

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

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

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

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

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity

does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

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

(20) *Production costs*.

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

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

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

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

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

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

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

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

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

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

Ÿ *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);*

Ÿ *The company's historical record at completing development of comparable long-term projects;*

Ÿ *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*

Ÿ *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*

Ÿ *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.