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

FORM 10-K

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

For the fiscal year ended December 31, 2018

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

For the transition period from_______ to ______
Commission file number: 001-37712

ROSEHILL RESOURCES INC.

(Exact Name of Registrant as Specified in its Charter)

Delaware	**47-5500436**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)

16200 Park Row, Suite 300
Houston, Texas 77084
(Address of principal executive offices)
(281) 675-3400

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

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

Indicate by check mark whether the registrant (1) filed all reports required to be filed by Section 13 or Section 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark 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	☐	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 Securities Exchange Act of 1934). Yes ☐ No☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2018, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $27.2 million based on the last sales price of the shares as reported on the NASDAQ market on that date.

As of March 22, 2019, 13,760,136 shares of Class A common stock, par value $0.0001 per share, and 29,807,692 shares of Class B common stock, par value $0.0001 per share, were issued and outstanding.

Documents Incorporated by Reference. Portions of the Definitive Proxy Statement for the registrant's 2019 Annual Meeting of Stockholders, to be filed within 120 days after December 31, 2018, are incorporated by reference into Part III of this report.

ROSEHILL RESOURCES INC.
FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2018

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GLOSSARY OF TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and natural gas industry and in this Annual Report on Form 10-K.

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

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.

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 used in reference to crude oil or other liquid hydrocarbons.

Bbls/d. Barrels per day.

Boe. One barrel of oil equivalent determined using a ratio of six thousand cubic feet (Mcf) of natural gas being equivalent to one Bbl of crude oil, condensate or natural gas liquids.

Boe/d. Barrels of oil equivalent per day.

***Btu*.** British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The process of treating a drilled 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. 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. For additional information, see the SEC's definition in Rule 4-10(a)(4) of Regulation S-X, a link for which is available at the SEC's website.

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

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

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

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.

Development well. A well drilled within the proved area of an oil or 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 well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

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.

Exploitation. A development 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 and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

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.

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

Fracturing. The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.

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

Henry Hub. A distribution hub of natural gas pipelines used as a benchmark in natural gas pricing and the underlying commodity of NYMEX natural gas futures contracts.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.

Horizontal wells. Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.

Hydrocarbons. Oil, NGLs and natural gas are all collectively considered hydrocarbons.

Liquids. Natural gas that contains significant heavy hydrocarbons, such as ethane, propane, butane, pentane and isobutane.

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

MBoe. One thousand barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet.

Mcf/d. One thousand cubic feet of natural gas per day.

Mineral interests. The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

Net acres. The sum of the fractional working interest owned in gross acres.

Net production. Production that is owned by the Company less royalties and production due others.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

Net wells. The sum of the fractional working interest owned in gross wells.

NGLs. The combination of ethane, propane, butane, pentane and isobutane that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

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.

Operating interest. An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

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

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.

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

Proved developed reserves. Reserves that can be expected to be recovered through: (i) 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.

Proved developed non-producing. Proved oil and natural gas reserves that are developed behind pipe or shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that 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 recompletion prior to the start of production.

Proved reserves. Proved oil and natural 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.

Proved undeveloped reserves ("PUD"). Proved undeveloped oil and gas 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.

(i) Proved 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) Proved 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.

(iii) Under no circumstances shall estimates for proved 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 or by other evidence using reliable technology establishing reasonable certainty.

PV-10. When used with respect to natural gas , oil and NGL reserves, PV-10 means the present value of the estimated future net revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as "present value." After-tax PV-10 is also referred to as "standardized measure" and is net of future income tax expense.

Realized price. The cash market price less all expected quality, transportation and demand adjustments.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

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 oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

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

SEC. United States Securities and Exchange Commission.

Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price for each month) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure. Standardized measure does not give effect to commodity derivative transactions.

Tight formation. A formation with low permeability that produces natural gas with very low flow rates for long periods of time.

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

Undeveloped oil, natural gas and NGL reserves. Undeveloped oil, natural gas and NGL 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. Also referred to as “undeveloped reserves.”

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and the right to a share of production.

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

West Texas Intermediate (“WTI”). A type of crude oil used as a benchmark in oil pricing and the underlying commodity of NYMEX oil futures contracts.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under "Risk Factors" in Item 1A of Part 1 of this Annual Report on Form 10-K. These forward-looking statements are based on management's current beliefs as of the date of this Annual Report on Form 10-K, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about:

- our future financial performance;
- our ability to realize the anticipated benefits of acquired mineral rights and other associated assets and interests in the Southern Delaware Basin in December 2017 (the "White Wolf Acquisition");
- our business strategy;
- our reserves;
- our drilling prospects, inventories, projects and programs;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, liquidity and capital required for our development program;
- our realized oil, natural gas and NGL prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our hedging strategy and results;
- our future drilling plans;
- our expansion plans and future opportunities;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our pending legal or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in the Annual Report on Form 10-K that are not historical.

You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including but not limited to those risks described under "Risk Factors" in Item 1A of Part 1 of this Annual Report on Form 10-K. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied by the forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report on Form 10-K are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report on Form 10-K.

PART I

ITEM 1. BUSINESS

Overview

Rosehill Resources Inc. (the “Company,” “Rosehill Resources,” “we,” “us,” or “our”) is an independent oil and natural gas company focused on the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin. We have drilling locations in ten distinct formations in the Delaware Basin in:

- Brushy Canyon
- Upper and Lower Avalon
- 2nd and 3rd Bone Spring Shale
- 2nd and 3rd Bone Spring Sand
- Wolfcamp A (X/Y)
- Lower Wolfcamp A
- Wolfcamp B

Our goal is to build a premier development and acquisition company focused on horizontal drilling in the Delaware Basin. We have no direct operations and no significant assets other than our ownership interest in Rosehill Operating Company, LLC (“Rosehill Operating:), an entity for which we act as the sole managing member and of whose common units we currently own approximately 31.6% (or 43.1% assuming the conversion of Rosehill Operating Series A preferred units into Rosehill Operating common units).

Class A common stock, par value $0.0001 (“Class A Common Stock”), and one warrant (“Public Warrant”), were issued in our initial public offering. Our Class A Common Stock Public Warrants and Units trade on The NASDAQ Capital Market (“NASDAQ”) under the ticker symbols “ROSE,” “ROSEW,” and “ROSEU,” respectively.

Presentation of Financial and Operating Data

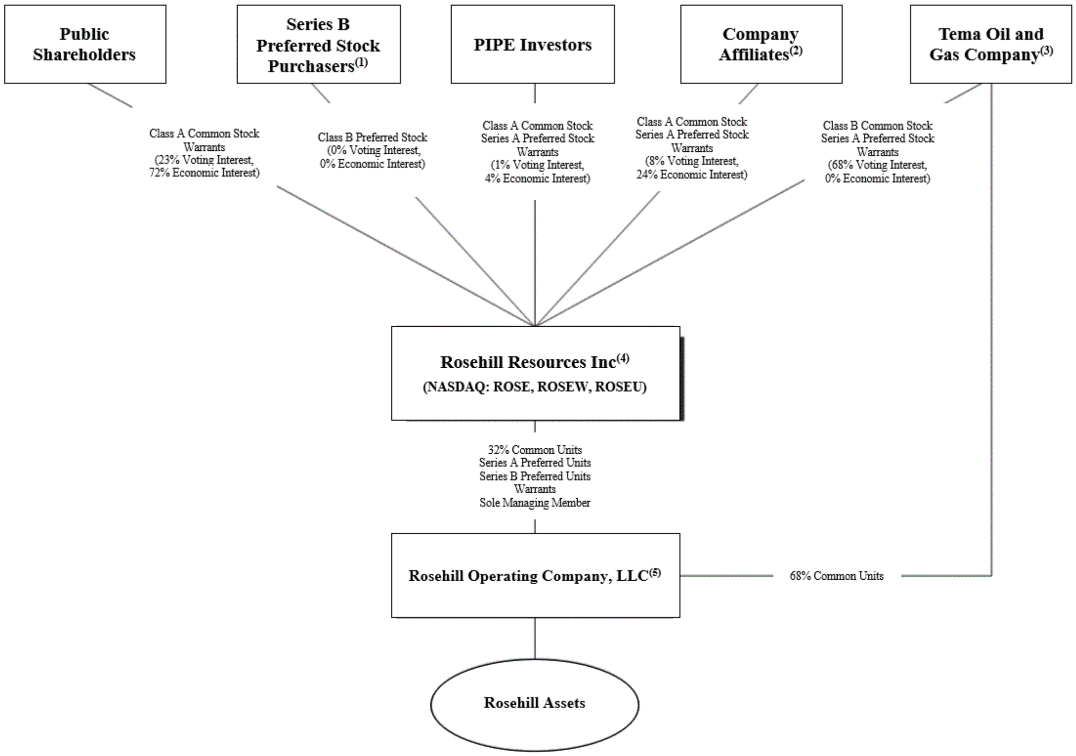
On April 27, 2017, the Company was formed when KLR Energy Acquisition Corporation (“KLRE”) acquired a portion of the equity interests of Rosehill Operating, an entity into which Tema Oil & Gas Company (“Tema”), a wholly owned subsidiary of Rosemore, Inc. (“Rosemore”), contributed certain assets and liabilities (the “Transaction”). Following the Transaction, KLRE changed its name to Rosehill Resources Inc. and became the sole managing member of Rosehill Operating.

The consolidated financial results of the Company consist of the financial results of Rosehill Resources, Inc. and Rosehill Operating, its consolidated subsidiary. Because Tema had effective control of the combined company before and after the consummation of the Transaction on April 27, 2017 through its majority voting interest in Rosehill Operating and the Company, respectively, the Transaction was structured as a reverse recapitalization. As a result, the reports filed by the Company subsequent to the Transaction are prepared “as if” Rosehill Operating is the predecessor and legal successor to the Company. The historical operations of Rosehill Operating are deemed to be those of the Company. Thus, the financial statements included in this report reflect:

- the historical operating results of Rosehill Operating prior to the Transaction;
- the combined results of the Company and Rosehill Operating following the Transaction;
- the assets and liabilities of Rosehill Operating at their historical cost; and the Company’s equity and earnings per share for all periods presented.

Organizational Structure

The following diagram illustrates the ownership structure of the company as of December 31, 2018:



(1) "Series B Preferred Stock Purchasers" refers to certain private funds and accounts managed by EIG Global Energy Partners, LLC.

(2) "Company Affiliates" refers to KLR Energy Sponsor, LLC, certain of our current and former directors and officers, and certain of our shareholders who own greater than 10% of the Company's common stock.

(3) Includes Class B Common Stock, Series A Preferred Stock and warrants held by Tema.

(4) The economic and voting interests set forth above do not take into account (i) the exercise of outstanding warrants for shares of Class A Common Stock, (ii) the future issuance of shares of Class A Common Stock under the Amended and Restated 2017 Long-Term Incentive Plan (the "Long Term Incentive Plan") or (iii) the conversion of Series A Preferred Stock into shares of Class A Common Stock or the redemption of Rosehill Operating Common Units (and corresponding shares of Class B Common Stock) for shares of Class A Common Stock.

(5) In connection with the conversion of our remaining Series A Preferred Stock into Class A Common Stock, the Rosehill Operating Series A Preferred Units owned by us will convert into Rosehill Operating Common Units and, on an as-converted basis, we will own approximately 43% of the Rosehill Operating Common Units.

Our Business

We are an independent oil and natural gas company focused on the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. The Permian Basin is located in West Texas and Southeastern New Mexico and is comprised of three primary sub-basins; the Midland Basin, the Central Basin Platform and the Delaware Basin. Since the sale of our Barnett Shale assets during the fourth quarter of 2017, our assets are concentrated within the Delaware Basin, and we divide our operations into two core areas: the Northern Delaware Basin and the Southern Delaware Basin.

Our sole material asset is our interest in Rosehill Operating. As the sole managing member of Rosehill Operating, we, through our officers and directors, are responsible for all operational, management and administrative decisions relating to Rosehill Operating's business without the approval of any other member, unless otherwise specified in the Second Amended and Restated Limited Liability Company Agreement of Rosehill Operating (the "Second Amended LLC Agreement").

Our management team has significant experience identifying, acquiring and developing unconventional oil and natural gas assets with the objective of being a returns-oriented pure-play Delaware Basin company focusing on (i) acreage with reduced development risk as a result of being in proven areas within the vicinity of other successful wells, (ii) stacked pay zones, including Brushy Canyon, Avalon/1st Bone Spring, 2nd Bone Spring, 3rd Bone Spring, Upper Wolfcamp A (X/Y), Lower Wolfcamp A and Wolfcamp B and (iii) application of geology, optimizing well process improvements and well returns. We believe these characteristics enhance our horizontal production capabilities, recoveries and economic results.

Recent Events

Class A Common Stock Offering

On September 27, 2018, we entered into an underwriting agreement (the "Underwriting Agreement") with Citigroup Global Markets Inc., as representative of the several underwriters named therein (the "Underwriters"), for a public offering of 6,150,000 shares of common stock (the "Class A Common Stock Offering") at a public offering price of $6.10 per share ($5.795 per share net of underwriting discount and commissions). Pursuant to the Underwriting Agreement, we granted the Underwriters a 30-day option to purchase up to an additional 922,500 shares of Class A Common Stock.

On October 2, 2018, upon the closing of the Class A Common Stock Offering, we issued 6,150,000 shares of Class A Common Stock. Our net proceeds from the Class A Common Stock Offering, net of underwriting discounts and commissions and offering costs, was $34.5 million. On October 5, 2018, the Underwriters exercised their option to purchase an additional 840,744 shares of Class A Common Stock at the Underwriters' price of $5.795 per share. We received net proceeds of approximately $4.9 million for the shares of Class A Common Stock sold pursuant to the exercise of the Underwriters' option. We contributed all of the net proceeds from the Class A Common Stock Offering and the exercise of the Underwriters' option to Rosehill Operating in exchange for Rosehill Operating Common Units.

Farm-In Agreement

In March 2019, we executed a farm-in agreement with Jagged Peak Energy covering the right to earn an interest in a strategic block in the Southern Delaware Basin. The farm-in agreement allows us to earn up to approximately 2,200 net acres upon drilling and completing up to seven wells through 2020. We will provide a 25% carry of drilling and completion costs for each of the seven wells, along with facilities equipment.

Amended and Restated Credit Agreement

On March 28, 2018, Rosehill Operating entered into an Amended and Restated Credit Agreement (the "Amended and Restated Credit Agreement") by and among Rosehill Operating, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders. Pursuant to the Amended and Restated Credit Agreement, the lenders agreed to provide Rosehill Operating with a $500 million secured reserve-based revolving credit facility with an initial borrowing base of $150 million. The first redetermination date occurred on June 29, 2018, increasing the borrowing base from $150 million to $210 million and then it was increased to $220 million on December 5, 2018. On March 28, 2019, the borrowing base was increased to $300 million.

Our Operations

We operate in one industry segment, which is the exploration, development and production of oil and natural gas, and all of our operations are conducted in the United States. Consequently, we currently report a single reportable segment. See the notes to our consolidated financial statements for financial information about this reportable segment. Our future development will be focused predominately on horizontal development drilling in both our core acreage areas in the Northern Delaware Basin and the Southern Delaware Basin. We currently have two horizontal rigs under contract of less than one year.

Since 2012, we have drilled 71 gross horizontal wells in the Northern Delaware Basin and 8 gross horizontal wells in the Southern Delaware Basin with a continuing drop in drilling times and an increase in operational capabilities and efficiencies. In 2018, our production was approximately 18,337 net barrels of oil equivalent per day, an increase of over 214% as compared to the daily average of 2017. As of December 31, 2018, our portfolio included 67 gross operated producing horizontal wells in the Northern Delaware Basin and 4 gross operated producing horizontal wells in the Southern Delaware Basin, as well as working interests in approximately 6,665 gross acres in the Northern Delaware Basin and 9,219 gross acres in the Southern Delaware Basin.

As of December 31, 2018, we have identified 513 gross operated and 53 gross non-operated potential horizontal drilling locations in the Northern and Southern Delaware Basin, including 44 locations associated with proved undeveloped reserves, in up to ten formations from Brushy Canyon down through the Wolfcamp B. We believe that development drilling of our identified gross operated potential horizontal drilling locations, together with an increased focus on maximizing the value of existing assets by optimizing completions, reducing horizontal drilling costs, efficiently building out facilities and reducing operating costs will allow us to grow our production and reserves. We also intend to grow our production and reserves through acquisitions that meet certain strategic and financial objectives.

The table below sets forth our identified potential operated horizontal drilling locations for the Northern and Southern Delaware Basin by formation as of December 31, 2018.

	Operated Potential Horizontal Drilling Locations (1)(2)(3)	
Target Formation:	**Gross**	**Net**
Brushy Canyon	27	24
Upper Avalon	13	13
Lower Avalon / 1st Bone Spring	83	74
2nd Bone Spring Shale	17	17
2nd Bone Spring Sand	59	55
3rd Bone Spring Shale	19	19
3rd Bone Spring Sand	57	49
Wolfcamp A (X/Y)	15	15
Lower Wolfcamp A	68	57
Wolfcamp B	155	137
Total Horizontal Locations (4)	513	460

(1) Our inventory of gross operated potential horizontal drilling locations assumes four to six wells per 640-acre section within each of the ten formations, with the number of prospective formations varying from tract to tract depending on the geology of the specific area.

(2) Our estimated drilling locations are based on well spacing assumptions and the evaluation of our horizontal drilling results as well as results of other operators in the area, combined with our interpretation of available geologic and engineering data. In particular, we have analyzed and interpreted well results and other data acquired through our participation in the drilling of a vertical well that penetrated all of our targeted horizontal formations. In addition, to evaluate the prospects of our horizontal acreage, we have performed open-hole and mud log evaluations, core analysis, and drill cuttings analysis and acquired and interpreted modern 3-D seismic data.

(3) The drilling locations that we actually drill will depend on the availability of capital, regulatory approvals, seasonal restrictions, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified potential horizontal drilling locations may not be successful and may not result in our ability to add additional proved reserves to our existing proved reserves. Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations. The identified potential horizontal drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the capital that would be necessary to drill such locations.

(4) Includes PUDs and unproved locations for our leasehold in the Northern and Southern Delaware Basins.

We expect to drill between 25 and 29 wells in 2019, completing between 24 and 28 wells. As of December 31, 2018, we had 8 drilled uncompleted wells ("DUCs") and expect to exit 2019 with 8 to 10 DUCs.

Our locations

Advanced petrophysical logs from the vertical portions of our wells, sidewall cores and seismic data are being utilized to guide our horizontal development of both the Northern Delaware area and the Southern Delaware area. The use of seismic data has resulted in a better understanding of our leasehold's geology relative to other parts of the basin. The depth to the top of the Wolfcamp from a representative well central to our Northern Delaware leasehold is approximately 11,500 feet true vertical depth and approximately 9,000 feet true vertical depth in the Southern Delaware. The gross thickness of the potential pay section from the top of the Brushy Canyon formation through the base of the Wolfcamp B is approximately 4,500 feet in the Northern Delaware, an attractive thickness for development with multiple horizontal landing formations. Similarly, the gross thickness of the potential pay thickness from the top of the Bone Spring Lime through the base of the Wolfcamp B in the Southern Delaware is approximately 2,500 feet. We believe that the combination of these conditions will allow us to achieve superior results during the development of our leasehold.

Historically, our horizontal drilling has been widespread across the majority of our lease acreage. We have established commercial production in eight distinct formations in the Northern Delaware Basin in the Upper Avalon, Lower Avalon, 2nd Bone Spring Shale, 2nd Bone Spring Sand, 3rd Bone Spring Sand, Upper Wolfcamp A (X/Y), Lower Wolfcamp A and Wolfcamp B. In addition, offset operators have drilled and are producing in all ten formations, from Brushy Canyon down through the Wolfcamp B, enabling us to evaluate our acreage across various geographic areas and stratigraphic formations. As of December 31, 2018, approximately 64.9% of our total net operated acreage was either held by production or under continuous drilling provisions. Offset operator activity within the 3rd Bone Spring Sand and the Wolfcamp formations as well as our recent successful Wolfcamp drilling program has been a catalyst for Rosehill Operating to generate a development program focused on the 3rd Bone Spring Sand, Upper Wolfcamp A (X/Y), Lower Wolfcamp A and Wolfcamp B formations in the Northern Delaware. Our development program in the Southern Delaware will focus largely on the Wolfcamp A and Wolfcamp B formations. We will closely monitor this offset activity and adjust our future development plans with information and best practices learned from other operators.

Completion design and our effective execution are the predominant factors that dictate relative well performance in an area or zone. We have an evolving completion strategy that includes methodical adjustments of parameters, testing of different well designs on adjacent locations with similar rock characteristics, constant monitoring and re-evaluation of results and ultimately tailoring completions to the conditions specific to an area or formation. Our current base completion design is a hybrid fracture stimulation-a combination of slickwater and cross-linked gel. The field-level rate of return is most influenced by incremental improvements in well performance and cost savings; our philosophy is to focus on both parameters, with an emphasis on performance enhancement.

We believe all ten formations represent opportunities across our core acreage in the Northern Delaware with opportunities in six different formations in the Southern Delaware. We plan to target those formations in our future drilling program. In this Annual Report on Form 10-K, identified gross potential drilling locations are defined as locations on operated and non-operated leaseholds specifically identified by geologic, engineering and economic assessment. We have estimated our drilling locations based on well spacing assumptions and the evaluation of our operated horizontal drilling results as well as results of other operators in our area. Well performances are combined with interpretation of available geologic and engineering data to generate a development model for the assets. In addition, to evaluate the prospects of our horizontal acreage, we have performed open-hole and mud log evaluations, core analysis and drill cuttings analysis. We have also acquired 48 square miles of 3-D seismic data in the Northern Delaware and 110 square miles in the Southern Delaware that has been used to aid in the interpretation of the prospective formations. The availability of local infrastructure, well performance results, subsurface data and other factors that management may deem relevant, such as easement restrictions and state and local regulations, are considered in determining such locations. The locations that we will actually drill will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs and actual drilling results, among other factors.

Based on our evaluation of applicable geologic and engineering data, we currently have approximately513 gross (460 net) identified potential operated horizontal drilling locations in multiple horizons on our acreage. We intend to continue to develop our reserves and increase production through development drilling and exploitation and exploration activities on this multi-year project inventory of identified potential drilling locations and through additional acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves.

Operational facilities

Our development plan includes the development of necessary infrastructure to lower our costs and support our drilling schedule and production growth. We expect to accomplish this goal primarily through contractual arrangements with third-party service providers. Our facilities are generally in close proximity to our well locations and include storage tank batteries, oil/natural gas/water separation equipment and artificial lift equipment. A crude oil gathering system and a natural gas gathering system are already in place and functioning. We have sufficient gathering systems and pipeline takeaway capacity to continue ongoing and planned operations into 2019. As we continue to drill and develop our Delaware Basin assets, we expect that additional tank battery, water disposal and intra-field gathering lines will be required. We have agreements in place with third-party natural gas and crude oil purchasers and processors to benefit from existing downstream infrastructure. We expect to continue to evaluate the marketplace to obtain additional transportation and gathering options and capacity in the form of new pipeline tie-ins.

Major customers

With respect to the core properties we operate in the Delaware Basin, we maintain contracts with Gateway Gathering and Marketing Company (“Gateway”) (an affiliate of Tema), Targa Delaware, LLC and Targa Crude Pipeline, LLC (collectively, referred to as “Targa”), Plains Pipeline, L.P. (“Plains”) and Brazos Midstream Operating, LLC (“Brazos”) to gather and transport the majority of our production. We deliver crude oil and natural gas to Gateway, Targa, Plains and Brazos and they gather, transport and redeliver the oil and natural gas to certain redelivery points for sale to our customers. Please read the section entitled “Gathering and Transportation” for more detail on our gathering and transportation contracts.

We sell our production to a relatively small number of customers, as is customary in the industry. We sell all of our natural gas and NGLs under contracts with terms generally greater than twelve months and all of our oil under contracts with terms generally less than twelve months. The following table shows the percentage of sales to each of our major customers that accounted for 10% or more of our total oil, natural gas and NGL sales for each year presented.

	Year Ended December 31,		
	2018	**2017**	**2016**
Customer			
Gateway (1)	60%	80%	70%
Plains	17	—	—
Targa	13	—	—
ETC Field Services, LLC	—	10	17
Enlink Midstream Services, LLC	—	—	10
Other	10	10	3
Total	100%	100%	100%

(1) For a further discussion see Note 15 - *Related Party Transactions*

The loss of any one or all of our significant customers as a purchaser could materially and adversely affect our revenues in the short-term. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any of our significant customers as a purchaser would not have a material adverse effect on our financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil, NGLs and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 87.5%. As of December 31, 2018, 64.9% of our net leasehold acreage was held by production.

Gathering and Transportation

Our oil and natural gas production from our core properties in the Northern Delaware Basin, except the Weber 26 lease, is delivered to our production facilities and then our oil is transported through Gateway's Raven Gathering System ("Raven") pipeline to the interconnection between the Raven pipeline and Plains pipeline and our natural gas production is transported through Gateway's Loving County Gas System ("LCGS") to the interconnection between LCGS Pipeline and our purchasers. We have a Crude Oil Gathering Agreement and a Gas Gathering Agreement with Gateway that will each expire in April 2027. Upon expiration, each agreement will continue on a year-to-year basis until terminated by either party. We do not control Gateway's gathering facilities.

Our oil and natural gas production from our Weber 26 lease is delivered to our production facilities and then transported through Targa's crude oil and natural gas pipeline and gathering systems to delivery points specified in the contracts for sale to our customers. We have a five-year Crude Oil Gathering Agreement with Targa, which became effective May 1, 2018, that upon expiration, will continue on a year-to-year basis until terminated by either party. We have a five-year Gas Gathering, Processing and Purchase Agreement with Targa, which became effective December 1, 2016, that upon expiration, will continue on a year-to-year basis until terminated by either party.

Our natural gas production from our core properties in the Southern Delaware Basin is delivered to our production facilities and then transported through Brazos' gas gathering system to delivery points specified in the contracts for sale to our customers. We have a fifteen-year Gas Gathering Agreement with Brazos, which became effective October 28, 2015, that upon expiration, will continue on a year-to-year basis until terminated by either party.

During the further development of our properties in the Northern and Southern Delaware Basins, we expect to consider all gathering and delivery infrastructure options in the areas of our production. Gateway has a right of first refusal to build gathering and delivery infrastructure for our properties in the Northern Delaware Basin.

Competition

The oil and natural gas industry is intensely competitive and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel, primarily based on price. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of developing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing and future federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Please see "Risk Factors - Risks Related to Our Operations - Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil or natural gas and secure trained personnel."

Seasonality of business

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. Weather conditions affect the demand for and prices of, oil, natural gas and NGLs. Due to these and other seasonal fluctuations, results of operations for quarterly periods may not be indicative of the results that may be realized on an annual basis. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Operational hazards and insurance

The oil and natural gas industry involves a variety of operating risks, including, but not limited to, the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high-pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies for certain property damages, control of well protection, general liability, commercial automobile, workers compensation, pollution liability (claims made coverage with a policy retroactive date), excess umbrella liability and other coverages.

Our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these operational hazards could cause a significant disruption to our business. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. See Item 1A. “Risk Factors - Risks Related to Our Operations - We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or the insurance may be inadequate to protect us against, these risks.”

We reevaluate the purchase of insurance, policy terms and limits annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. 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. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

Generally, we also require our third-party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider’s employees as well as contractors and subcontractors hired by the service provider.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with these laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impacts of compliance. Proposals and proceedings that could affect the oil and natural gas industry are regularly considered by the United States Congress (“Congress”), the states, the Federal Energy Regulatory Commission (“FERC”), the U.S. Environmental Protection Agency (“EPA”), other federal agencies and the courts. We cannot predict when or whether any such proposals may become effective. However, we do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Regulation of oil and natural gas production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. We own property interests in jurisdictions that regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, bonding requirements to drill or operate wells, reports concerning operations and regulating the location of wells, the method of drilling and casing wells, the source and disposal of water used in the drilling and completion process, and the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations, including the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area and the unitization or pooling of crude oil or natural gas wells, as well as regulations that limit or prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws also govern various conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density and plugging and abandonment of wells. The effect of these regulations may limit the amount of oil and natural gas that we can produce from our wells and limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, many jurisdictions impose a production or severance tax with respect to the production and sale of oil, NGLs and natural gas within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of oil sales and transportation

Sales of oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe that the regulation of oil transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated. In December 2015, H.R. 2029 was signed into law which lifted a ban on the export of crude oil from the United States. This will enable U.S. oil producers the flexibility to seek new markets and export oil into the global marketplace.

Regulation of natural gas sales and transportation

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

The transportation and sale for resale of natural gas in interstate commerce is regulated by FERC primarily under the Natural Gas Act of 1938, as amended (“NGA”) and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The EP Act of 2005 amended the NGA to add an anti-market manipulation provision that makes it unlawful for any entity to engage in prohibited behavior prescribed by FERC Pursuant to the EP Act of 2005, FERC promulgated regulations that make it unlawful to: (i) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, use, or employ any device, scheme, or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the Annual Reporting requirements described below.

The EP Act of 2005 also provided FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increased FERC’s civil penalty authority under the NGA from $5,000 per violation per day to $1,000,000 per violation per day. Effective January 2018, to account for inflation, FERC’s civil penalty authority was increased to $1,238,271 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. Under FERC's regulations, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas producers, gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices, and whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC under the NGA. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities are done on a case-by-case basis. To the extent that FERC issues an order that reclassifies certain non-jurisdictional gathering facilities as jurisdictional transmission facilities, our costs of transporting gas to point of sale locations could increase. We believe that the third-party natural gas pipelines on which our gas is gathered meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of those gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

For physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC under the EP Act of 2005 and under the Commodity Exchange Act ("CEA") and regulations promulgated thereunder by the U.S. Commodity Futures Trading Commission. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures or derivative contracts on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity, as well as any manipulative or deceptive device or contrivance in connection with any contract of sale of any commodity in interstate commerce or futures or derivative contract on such commodity. Should we violate the anti-market manipulation laws and regulations, they could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship our natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenue we receive for sales of our natural gas.

Changes in law and to FERC or state policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect our operations in a way that materially differs from the way they will affect other natural gas producers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to occupational health and safety, or the protection of the environment and natural resources. Numerous federal, state and local governmental agencies, such as the EPA, issue regulations that often require difficult and costly 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 or seismically sensitive areas and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing 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 our operations or related to our owned or operated facilities. Liability under such laws and regulations is often strict (i.e., no showing of "fault" is required) and can be joint and several. 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. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Regulation of hazardous substances and waste handling

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ("CERCLA"), also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Although petroleum substances such as crude oil and natural gas are excluded from the definition of hazardous substances under CERCLA, various substances used in drilling and production operations are not covered by this exclusion and releases of these non-excluded substances or petroleum substances could give rise to CERCLA liability. 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 or petroleum released into the environment. We are only able to directly control the operation of those wells for which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the liability of an operator other than us for releases may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances, but we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act ("RCRA") and analogous state laws impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, in the course of our operations, we may generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics or are listed hazardous wastes. In addition, even wastes excluded from the definition of hazardous waste may be regulated by the EPA or state agencies under state laws or other federal laws. Moreover, it is possible that those particular oil and natural gas development and production wastes now excluded from the definition of hazardous wastes could be classified as hazardous wastes in the future. For example, from time to time various environmental groups have challenged the EPA's exclusion of certain oil and gas wastes from regulations RCRA. In one such challenge, the U.S. District Court for the District of Columbia entered a consent decree requiring EPA to evaluate the exclusion and, by March 2019, to either sign a notice of proposed rulemaking revising the regulations excluding oil and gas wastes or sign a determination that revision of the exclusion is not necessary. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes, if the EPA were to eliminate the exclusion, could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas development and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property, or performance of remedial plugging or pit closure operations to prevent future contamination.

Regulation of water discharges

The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into or near navigable 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 discharge of dredge and fill material into regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the “Corps”). In September 2015, the EPA and the Corps issued new rules defining the scope of the EPA’s and the Corps’ jurisdiction under the Clean Water Act with respect to certain types of waterbodies and classifying these waterbodies as regulated wetlands. The 2015 rule was previously stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases challenging the new rules. The EPA and the Corps issued a proposed rulemaking in June 2017 to repeal the June 2015 rule and announced their intent to issue a new rule defining the Clean Water Act’s jurisdiction. In January 2018, the U.S. Supreme Court issued a decision finding that jurisdiction resides with the federal district courts; following which, the previously-filed district court cases were allowed to proceed. Following the Supreme Court’s decision, the EPA and the Corps issued a final rule in January 2018 staying implementation of the 2015 rule for two years while the agencies reconsidered the rule. Multiple states and environmental groups challenged the stay and a federal judge barred the agencies’ suspension of the rule in August 2018. Separately, a federal court in Georgia enjoined implementation of the rule in eleven states. However, in December 2018, the EPA and the Corps released a proposed rule that would replace the 2015 rule and significantly reduce the waters subject to federal regulation under the Clean Water Act. Such proposal is currently subject to public review and comment, after which additional legal challenges are anticipated. As a result of these recent developments, future implementation of the 2015 rule is uncertain. To the extent any revised rule expands the scope of the Clean Water Act’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Obtaining permits has the potential to delay the development of oil and natural gas projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of pollutants in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

In addition, pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” for on-site storage of significant quantities of oil. We believe that we maintain all required discharge permits necessary to conduct our operations and further believe we are in substantial compliance with the terms thereof.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 (“OPA”), which amends and augments the oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of “responsible party” who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Regulation of air emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standards ("NAAQS") for ozone from 75 to 70 parts per billion. In November 2017, the EPA published a list of areas that are in compliance with the new ozone standard and, separately in December 2017, issued responses to state recommendations for designating non-attainment areas. States had the opportunity to submit new air quality monitoring to the EPA prior to the EPA finalizing its non-attainment designations. The EPA issued final attainment status designations in April 2018 and July 2018. State implementation of the revised NAAQS could result in stricter permitting requirements or could delay or limit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant.

In addition, the EPA has adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. More recently, 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 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. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Regulation of greenhouse gas emissions ("GHG")

In response to findings that emissions of carbon dioxide, methane and other GHG present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the federal Clean Air Act that, among other things, require preconstruction and operating permits for GHG emissions from certain large stationary sources that otherwise require such permits for non-GHG emissions. Facilities required to obtain preconstruction permits for their GHG emissions are also required to meet "best available control technology" standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability 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 certain of our operations. Furthermore, in June 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. However, the agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of these methane standards in their entirety. In September 2018, the EPA proposed amendments to the 2016 rules that would reduce the 2016 rules' fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the 2016 rules and the EPA's attempts to delay the implementation of such rules. As a result of these developments, future implementation of the standards is uncertain at this time. To the extent implemented, compliance with these rules would require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks and increased frequency of maintenance and repair activities to address emissions leakage. The rules would also likely require hiring additional personnel to support these activities or the engagement of third-party contractors to assist with and verify compliance. New rules related to the reduction of methane and other GHG emissions could result in increased compliance costs on our operations.

There have not been significant legislative proposals to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional programs and initiatives have been enacted or are being considered that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs, direct taxation of carbon emissions, or that promote the use of less carbon-intensive fuels. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. At the international level, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that requires member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. The Paris Agreement entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges from participating nations to voluntarily limit or reduce future emissions. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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 such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel 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 to secure funding for 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. 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 climatic events. Our operations are onshore and not located in coastal or flood-prone regions of the United States, but if any such effects were to occur at our locations, these effects have the potential to cause physical damage to our assets or affect the availability of water for our operations and thus could have a material adverse effect on our operations.

Regulation of hydraulic fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act ("SDWA") to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the Safe Drinking Water Act. Also, in June 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants.

The EPA has issued final regulations under the federal Clean Air Act that establish air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. These rules require a 95% reduction in volatile organic compounds emitted from these activities by requiring the use of reduced emission completions or "green completions" on new hydraulically-fractured wells. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

The EPA has also released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events.

Several states, including Texas, and local jurisdictions, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, the Texas Railroad Commission has adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The Texas Railroad Commission has also adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. The disposal well rule amendments also clarify the Texas Railroad Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Texas Railroad Commission has used this authority to deny permits for waste disposal wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, 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 that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities 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. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

ESA and migratory birds

The Endangered Species Act ("ESA") and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered or proposed for listing are known to exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service was required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the Agency's 2017 fiscal year. The agency missed this deadline and continues to review species for listing under the ESA. Also, in the past, the federal government has issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. However, in December 2017, the Department of Interior issued a new opinion revoking its prior enforcement policy and concluded that an incidental take is not a violation of the Migratory Bird Treaty Act. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as a critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Act OSHA and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities and to maintain these permits and compliance with their requirements for ongoing operations. These permits are generally subject to protest, appeal, or litigation, which, in certain cases, can delay or halt projects and cease production or operation of wells, pipelines and other operations.

Employees

As of December 31, 2018, we had 79 full-time employees. None of our employees are represented by labor unions or covered by collective bargaining agreements, and we have not experienced any strikes or work stoppages. Our future success will depend partially on our ability to identify, attract, retain and motivate qualified personnel. We consider our relations with our employees to be satisfactory.

Offices

Our principal executive offices are located at 16200 Park Row, Suite 300, Houston, Texas 77084, and our telephone number at that address is (281) 675-3400. We also have office space in Midland, Texas.

Available information

We are required to file quarterly and annual reports, current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Our filings with the SEC are also available to the public at the SEC's website at http://www.sec.gov. Our Class A Common Stock is listed and traded on the NASDAQ Capital Market under the symbol "ROSE."

We also make available on our website (http://www.rosehillresources.com) all documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Ethics and Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating and governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our corporate offices at 16200 Park Row, Suite 300, Houston, Texas 77084. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

ITEM 1A. RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. The following risks and uncertainties, together with other information set forth in this Annual Report on Form 10-K, should be carefully considered by current and future investors in our securities. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties presently unknown to us or currently deemed immaterial also may impair our business operations. The occurrence of one or more of these risks or uncertainties could materially and adversely affect our business, our financial condition, our cash flows and the results of our operations, which in turn could negatively impact the value of our securities.

Risks Related to Our Operations

Oil, natural gas and NGL prices are volatile. A reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition, cash flows and results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our revenues, profitability, cash flows and future growth, as well as liquidity and ability to access additional sources of capital, depends substantially on prevailing prices for oil, natural gas and NGLs. A reduction in or sustained lower prices will reduce the amount of oil, natural gas and NGLs that we can economically produce and may result in impairments of our proved reserves or reduction of our proved undeveloped reserves. Oil, natural gas and NGL prices also affect the amount of cash flow available for capital expenditures and ability to borrow and raise additional capital.

The markets for oil, natural gas and NGLs have historically been volatile. For example, since 2014, the WTI spot price for oil declined from a high of $107.95 per barrel in June 2014 to a low of $26.19 per barrel in February 2016 and ended at $45.15 per barrel on December 31, 2018. The NYMEX Henry Hub spot price for natural gas declined from a high of $8.15 per MMBtu in February 2014 to a low of $1.49 per MMBtu in March 2016 and ended at $3.25 per MMBtu on December 31, 2018. Likewise, NGLs, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics, have been volatile. The price of propane (Mont Belvieu) ranged from a high of $1.70 per gallon in January 2014 to a low of $0.30 per gallon in January 2016 and ended at $0.64 per gallon on December 31, 2018, and the price of ethane (Mont Belvieu) ranged from a high of $0.45 per gallon in January 2014 to a low of $0.14 per gallon in December 2016 and ended the year at $0.29 per gallon on December 31, 2018.

The market prices for oil, natural gas and NGLs depend on factors beyond our control. Some, but not all, of the factors that can cause fluctuation include:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the price and quantity of foreign imports of oil, natural gas, and NGLs;

- political and economic conditions in, or affecting, other producing regions or countries, including the Middle East, Africa, South America and Russia;
- actions of the Organization of the Petroleum Exporting Countries ("OPEC"), its members and other state-controlled oil companies, including the ability of members of OPEC to agree to and maintain price and production controls;
- the level of global exploration, development and production;
- the level of global inventories;
- the extent to which U.S. shale producers become "swing producers" adding or subtracting to the world supply;
- prevailing prices on local price indexes in the area in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions, other natural disasters and climate change;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- worldwide conservation measures;
- domestic and foreign governmental relations, regulation and taxes;
- worldwide governmental regulation and taxes;
- U.S. and foreign trade restrictions, regulations, tariffs, agreements and treaties;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- political conditions or hostilities and unrest in oil producing regions; and
- market perceptions of future prices, whether due to the foregoing factors or others.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of oil, natural gas and NGLs that we can produce economically and may impact our ability to satisfy our obligations under firm-commitment transportation agreements.

Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits. While it is difficult to project future economic conditions and whether such conditions will result in impairment of proved property costs, we consider several variables including specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors. In addition, sustained periods with oil and natural gas prices at levels lower than current strip prices and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone or eliminate our development drilling, which could result in the reduction of some of our proved undeveloped reserves. If we are required to curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our development and acquisition projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves.

The oil and natural gas industry is capital-intensive. We make substantial capital expenditures related to development and acquisition projects. We expect to fund our capital expenditures with cash generated by operations and borrowings under the Company's Amended and Restated Credit Agreement, dated as of March 28, 2018, by and among Rosehill Operating, Rosehill and JPMorgan Chase Bank, N.A., as administrative agent and issuing bank, and each of the lenders from time to time party thereto (the "Amended and Restated Credit Agreement"); however, financing needs may require an alteration or increase in our capitalization substantially through the issuance of debt or equity or the sale of assets. The issuance of additional debt securities would require that a portion of the cash flow from our operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities would be dilutive to stockholders. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things: oil, natural gas and NGL prices; actual drilling results; the availability and cost of drilling rigs and other services and equipment; and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which our production is sold;
- our proved reserves;
- the volume of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses;
- our ability to borrow under our Amended and Restated Credit Agreement (or any replacement credit facility); and
- our ability to access the capital markets.

If cash flow from operations or available borrowings under our Amended and Restated Credit Agreement decrease as a result of lower oil, natural gas and NGL prices, operational difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on acceptable terms, if at all. If cash flow from operations or available under existing or anticipated credit facilities are insufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of the development of our properties, which in turn could lead to a decline in our reserves and production and could materially and adversely affect our business, financial condition and results of operations.

Drilling for oil and natural gas involves numerous and significant risks and uncertainties.

Risks that we face while drilling wells include:

- effects of weather, floods, snowstorms, ice storms and similar natural conditions, on the drilling location and delivery of materials to the wellsite;
- unforeseen water flows;
- lost circulation of drilling fluids;
- unexpected oil and gas flows into the wellbore;
- drill pipe, casing and equipment failure, or loss of equipment in the well;
- failure or inaccuracies of directional drilling measurement devices;
- excessive hole washouts in the salt/anhydrite zones resulting in poor surface cement jobs;
- inability to reach the desired drilling zone with conventional bits and drilling techniques;
- failure to land a wellbore in the desired drilling zone;
- inability to stay in the desired drilling zone or being able to run tools and other equipment consistently while drilling horizontally through the formation; and
- difficulties in running casing the entire length of the wellbore.

Risks that we face while completing wells include:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. Furthermore, the results of our 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 have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as anticipated, and we could incur material write-downs of unevaluated properties and a decline in the value of our undeveloped acreage.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our development, acquisition and production activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to develop or purchase prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.” In addition, our cost of drilling, completing and operating wells is often uncertain.

Many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including limitations resulting from wastewater disposal, emissions of GHGs and limitations on hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, including such conditions which are possibly connected to climate change;
- drought conditions limiting the availability of water for hydraulic fracturing, including such conditions as possibly connected to climate change;
- issues related to compliance with environmental regulations, including protections for threatened or endangered species;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for oil and natural gas.

Our derivative activities could result in financial losses or could reduce our earnings.

A portion of our oil and natural gas production has historically been hedged in order to protect cash flow from falling prices. The use of these arrangements limits our ability to benefit from increases in the prices of natural gas and oil. As of December 31, 2018, we had open commodity derivative contracts for the months of January 2019 through December 2022 covering a total of 13.3 million barrels of oil, 6.1 million MMBtus of natural gas, 2.8 million gallons of NGLs (natural gas), 12.4 million gallons of NGLs (ethane) and 8.3 million gallons of NGLs (propane). Additionally, we had crude oil basis swaps covering a total of 8.3 million barrels of oil and natural gas basis swaps covering a total of 3.9 million MMBtus of natural gas. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our commodity derivative.

Commodity derivatives may also expose us to the risk of financial loss in some circumstances, including when:

- production and sales are insufficient to offset losses under the commodity derivatives;
- the counterparty to the commodity derivatives defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the commodity derivatives and actual prices received;
- issues arise with regard to legal enforceability of such instruments; or
- applicable laws or regulations regarding such instruments are changed.

The use of commodity derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into commodity derivatives that require cash collateral, particularly if commodity prices or interest rates change in a manner averse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with counterparties, highly volatile oil and natural gas prices and interest rates. In addition, commodity derivatives could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our commodity derivative contract receivable positions have generally increased, which has increased our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our commodity derivative contracts.

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected, and production declines may be greater than our estimates and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves.

You should not assume that the present value of future net revenues from our estimated reserves is the current market value of such reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, our estimated proved reserves as of December 31, 2018 were, and related standardized measure was, calculated under SEC rules using twelve-month unweighted average first-day-of-the-month prices of $65.56 per barrel of oil (WTI), $23.02 per barrel of NGL (35% of WTI) and $3.10 per MMBtu of natural gas (Henry Hub) which, for certain periods in 2018, were substantially higher than the available spot prices. If spot prices are below such calculated amounts, using more recent prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of our drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

We have specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the potential drilling locations our management has identified will ever be drilled or if we will be able to produce oil or natural gas in commercial qualities from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2018, 513 gross operated potential horizontal drilling locations have been identified on our acreage based on four to six wells per 640-acre section within each of ten formations from the Brushy Canyon through Wolfcamp B formations, of which 44 were PUDs. Horizontal lateral effective lengths across our acreage range from 4,000 feet up to 10,000 feet. As a result of the limitations described above, we may be unable to drill many of the identified locations. Further, in connection with the White Wolf Acquisition, we acquired approximately 6,505 net acres in northwestern Pecos County, Texas, which is largely unproven and relatively undrilled compared to other areas in the Delaware Basin. We have no experience drilling in Pecos County. Based on future operations or regulatory changes, we may determine that certain formations cannot be physically or economically exploited or that spacing of wells may have to be changed.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. See "Our development and acquisition projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves." Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed.

As of December 31, 2018, approximately 64.9% of our total net acreage was either held by production or under continuous drilling provisions. The leases for our net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases, the leases are held beyond their primary terms under continuous drilling provisions or the leases are renewed. If our leases expire and we are unable to renew the leases, we will lose the right to develop the related properties. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas drilling and hydraulic fracturing processes. Drought conditions have persisted in Texas in past years. These drought conditions have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

All of our producing properties are located in the Delaware Basin, a sub-basin of the Permian Basin, in West Texas and New Mexico, making us vulnerable to risks associated with operating in a single geographic area.

All of our producing properties are geographically concentrated in the Delaware Basin, a sub-basin of the Permian Basin, in West Texas. At December 31, 2018, 100% of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

In addition to the geographic concentration of our producing properties in the Delaware Basin described above, at December 31, 2018, approximately 68% percent of our proved reserves were attributable to the 3rd Bone Spring, Wolfcamp A (X/Y) and Lower Wolfcamp A formations. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace the current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be materially and adversely affected.

We will not be the operator on all of our acreage or drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

As of December 31, 2018, we have leased or acquired approximately11,583 net acres in the Delaware Basin, approximately 93.1% of which we operate. As of December 31, 2018, we were the operator on 513 of our 566 identified gross horizontal drilling locations. We expect to operate approximately91.5% of, and have an approximate 91.0% working interest in, the acreage we own in the Southern Delaware Basin and believe that the acreage may be prospective for six different shale formations. We will have limited ability to exercise influence over the operations of the drilling locations we do not operate, and the operators of those locations may at any time have economic, business or legal interests or goals that are inconsistent with us. Furthermore, the success and timing of development activities by such operators will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator’s expertise and financial resources;
- the approval of other participants in drilling wells;
- the selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations and associated costs of some of our non-operated drilling locations could prevent the realization of targeted returns on capital in drilling or acquisition activities.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We own less than 100% of the working interest on a minority of the oil and gas leases on which we conduct operations, and other unrelated parties own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could potentially be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. Other working interest owners may be unable or unwilling to pay their share of project costs, and, in some cases, may declare bankruptcy. In the event any other working interest owners do not pay their share of such costs, we would likely have to pay those costs, and may be unsuccessful in any efforts to recover these costs from other working interest owners, which could materially adversely affect our financial position.

The marketability of our production will be dependent upon transportation and other facilities, certain of which we will not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil production from our Loving County wells is transported through Gateway’s Raven pipeline from the wellhead to the interconnection between Raven pipeline and Plains Marketing, LP (“Plains Marketing”) pipeline, where Plains Marketing purchases the oil. The oil is then transported on a third-party pipeline to a location where it is resold. Our oil production from our Weber 26 lease wells is purchased at the wellhead by Targa Delaware, LLC and oil production from our Tatanka lease well is purchased at the wellhead by Plains Marketing and subsequently transported on a third-party pipeline to a location where it is resold.

Our natural gas production from our Loving county wells is transported by Gateway on Gateway's LCGS pipeline from the wellhead to the interconnection between LCGS pipeline and Delaware G&P LLC pipeline and ETC Field Services pipeline. The gas is sold by us to Delaware G&P LLC ("Delaware G&P")and ETC Field Services at the interconnection between LCGS and Delaware G&P and ETC Field Services. Delaware G&P and ETC Field Services transport the gas to their processing facilities. Our natural gas production from our Weber 26 lease wells is purchased at the wellhead by Targa Delaware, LLC and natural gas production from our Tatanka lease well is purchased at the wellhead by ETC Field Services and subsequently transported on a third-party pipeline to their gas processing facilities.

We entered into crude oil gathering and natural gas gathering agreements with Gateway, for production from our Loving County wells, that will expire in April 2027. We do not control Gateway's or the third-party's transportation and processing facilities and our access to the facilities may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production or flare natural gas. Any such shut-in, curtailment, or flaring or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in our quarterly operating results.

We may incur losses as a result of title defects in the properties in which we invest.

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we have historically obtained title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property and may be required to pay damages to the actual owner of the lease.

Concerns over economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European, Asian and the United States financial markets have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish further, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than currently anticipated. Therefore, our estimated PUDs may not be ultimately developed or produced.

As of December 31, 2018, 43.5% of our total estimated proved reserves were classified as PUDs. Development of these PUDS may take longer and require higher levels of capital expenditures than currently anticipated. For example, primarily as a result of factors outside our control, including a downturn in commodity prices during 2014, we adjusted our development plan to temporarily defer the drilling of certain PUD locations. As a result, no PUDs were converted from undeveloped to developed during 2015 and 2016. As a result of our failure to convert any PUDs during 2015 and 2016, we will have a shorter period of time available to convert such PUDs (due to the requirement to convert PUDs from undeveloped to developed within five years of initial booking). Further delays in the development of our PUDs, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs and future revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our PUDs as unproved reserves if we no longer believe with reasonable certainty that we will develop the PUDs within five years after their initial booking. If we do not drill our PUD wells within five years after their respective dates of booking, we may be required to write-down our PUDs.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take impairments or write-downs of the carrying values of our properties.

Accounting rules require periodic review of the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. Commodity prices have declined significantly in recent years. For example, the WTI spot price for oil declined from a high of $107.95 per barrel in June 2014 to a low of $26.19 per barrel in February 2016, and the NYMEX Henry Hub spot price for natural gas declined from a high of $8.15 per MMBtu in February 2014 to a low of $1.49 per MMBtu in March 2016. Likewise, NGLs have suffered significant recent declines in realized prices. The price of propane (Mont Belvieu) ranged from a high of $1.73 per gallon in February 2014 to a low of $0.30 per gallon in January 2016 and the price of ethane (Mont Belvieu) ranged from a high of $0.45 per gallon in January 2014 to a low of $0.13 per gallon in December 2015. Impairment expense for the years ended December 31, 2018, 2017 and 2016 was zero, $1.1 million and zero, respectively. Lower commodity prices in the future could result in impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Conservation measures and technological advances could reduce demand for oil and natural gas.

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 may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We depend upon significant purchasers for the sale of most of our oil, natural gas and NGL production.

We have historically sold our production to a relatively small number of customers, as is customary in our business. For the year ended December 31, 2018 and 2017, three and two customers accounted for approximately 90% and 90%, respectively, of our total revenue. During such periods, no other purchaser accounted for 10% or more of our revenue. The loss of any one or all of our significant customers as a purchaser could materially and adversely affect our revenues in the short-term.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, occupational health and safety aspects of our operations, or otherwise relating to the protection of the environment and natural resources. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated activities; the restriction of the types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; or the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions may require us to perform difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations and the issuance of orders limiting or prohibiting some or all of our operations; and plugging and abandonment responsibilities for wells which have ceased producing. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

Certain environmental laws impose strict as well as joint and several liabilities for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been released into the environment. We may be required to remediate contaminated properties currently or formerly operated by us or our predecessors in interest or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us. The trend has been for more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry, resulting in increased costs of doing business and consequently affecting profitability. For example, in June 2016, the EPA finalized a rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. In addition, in October 2015, the EPA lowered the NAAQS for ozone from 75 to 70 parts per billion. In November 2017, the EPA published a list of areas that are in compliance with the new ozone standards and separately in December 2017 issued responses to state recommendations for designating non-attainment areas. The EPA issued final non-attainment area designations in April 2018 and July 2018. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or the insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and development activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and air contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and drill pipe or casing failures or collapse;
- fire, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters, which may include severe weather as possibly connected to climate change and seismic events as possibly connected to injection of produced water and flowback into disposal wells; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- statutory or regulatory investigations and penalties; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, statutory and regulatory penalties, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields and data from other wells in the same area, or more fully explored prospects, will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, in commercial quantities. Further, drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected or adverse drilling conditions;
- title problems;
- elevated pressure or lost circulation in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may be unable to make attractive acquisitions or successfully integrate acquired assets or businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future, we may make acquisitions of assets or businesses that complement or expand our current business. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired assets or business. The process of integrating acquired assets or businesses may involve unforeseen difficulties and may require a disproportionate amount of managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional 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 and results of operations, which may cause the market price of our Class A Common Stock to decline.

In addition, our Amended and Restated Credit Agreement, Certificate of Designation for the Series B Preferred Stock filed with the Secretary of State of the State of Delaware on December 8, 2017 ("Series B Certificate of Designation") and the Note Purchase Agreement, dated as of December 8, 2017 (as amended by the Limited Consent and First Amendment to the Note Purchase Agreement, dated as of March 28, 2018, the "Note Purchase Agreement") impose, and future debt agreements may impose, among other things, limitations on our ability to enter into mergers or combination transactions. See "Risks Related to Our Indebtedness - Restrictions in our Amended and Restated Credit Agreement, Certificate of Designation for the Series B Preferred Stock and the Note Purchase Agreement limit, and our future debt agreements could limit, our ability to engage in certain activities." Such limitations may also restrict our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of assets or businesses.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- geological risks;
- access to markets;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. However, these reviews will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, 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.

Certain of our properties are subject to land use restrictions, which could limit the manner in which we conduct our business.

In order to bring equipment, supplies, water, personnel and produced products to and from certain of our properties, we and/or our contractors must obtain permissions or rights-of-way from other parties, including private property owners and governmental agencies. There is no guarantee that we or our contractors will be able to obtain or continue to obtain those permissions or rights or to obtain them at a reasonable cost. In addition, certain of our properties are subject to land use restrictions, including ordinances, which could limit the manner in which we conduct our business. Although none of our proposed drilling locations associated with proved undeveloped reserves as of December 31, 2018 are on properties currently subject to such land use restrictions, such restrictions may become effective in the future. All of the permissions, rights-of-way and restrictions discussed above could affect, among other things, our access to and the permissible uses of our facilities as well as the manner in which we produce oil and natural gas and may restrict or prohibit drilling in general. The costs incurred to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of development activities and may even be precluded from the drilling of wells.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

We do not own any drilling rigs, nor do we own other equipment and supplies that are critical to our continuing ability to drill for and produce oil, gas and NGLs. We are dependent on access to qualified and competent contractors for such equipment and supplies, as well as the personnel to engage in our drilling and production program. The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Our operations are concentrated in areas in which industry has increased rapidly, and as a result, demand for such drilling rigs, equipment and personnel, as well as access to transportation, processing and refining facilities in these areas, has increased, as have the costs for those items. We may not be able to renew or obtain new drilling contracts for rigs whose contracts are expiring or are terminated or obtain drilling contracts for our uncontracted new builds. Any delay or inability to secure the personnel, including frac crews, equipment, power, services, resources and facilities access necessary for us to increase our development activities could result in production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our cash flow and profitability. Furthermore, if we are unable to secure a sufficient number of drilling rigs at reasonable costs, we may not be able to drill all of our acreage before our leases expire.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Decreased levels of drilling activity in the oil and gas industry in recent periods have led to declining costs of some drilling equipment, materials and supplies. However, such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our prior or future commodity derivative activities.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Domenici-Barton Energy Policy Act of 2005, FERC has civil penalty authority under the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to impose penalties of up to $1,238,271 per day for each violation for current violations and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC's annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the federal Clean Air Act that, among other things, require preconstruction and operating permits for GHG emissions from certain large stationary sources that otherwise require such permits for non-GHG emissions. Facilities required to obtain preconstruction permits for their GHG emissions are also required to meet "best available control technology" standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability 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 certain of our operations. Furthermore, in June 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rules include first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards, but the EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. In February 2018, the EPA finalized amendments to some of the requirements of the June 2016 rule, although the EPA's reconsideration of the aspects of the rule is ongoing. To the extent implemented, compliance with these rules would require enhanced record-keeping practices, the purchase of new equipment, such as optical gas imaging instruments to detect leaks, and increased frequency of maintenance and repair activities to address emissions leakage. The rules would also likely require additional personnel time to support these activities or the engagement of third party contractors to assist with and verify compliance. Although on September 11, 2018, the EPA issued propose revisions to the New Source Performance Standards applicable to new and modified oil and gas sources, which would reduce the monitoring obligations for wells and compressor stations, new rules related to the reduction of methane and GHG emissions could result in increased compliance costs on our operations.

There have not been significant legislative proposals to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional programs and initiatives have been enacted or are being considered that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs, direct taxation of carbon emissions, or that promote the use of less carbon-intensive fuels. At the international level, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, which resulted in an agreement (the "Paris Agreement") that requires member countries to review and "represent a progression" in their intended nationally determined contributions, and set GHG emission reduction goals every five years beginning in 2020. The Paris Agreement entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges from the participating nations to voluntarily limit or reduce future emissions. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs on different terms. In August 2017, the U.S. Department of State provided official notice to the United Nations of the United States' intent to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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 such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel 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 to secure funding for 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. 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 climatic events. Our operations are onshore and not located in coastal or flood-prone regions of the United States, but if any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water for our operations and thus could have a material adverse effect on our operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations and expect to continue that practice. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also issued: final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; and also finalized rules 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. As described elsewhere in this Annual Report on Form 10-K, these risks are regulated under various federal, state and local laws. The EPA's study report did not find a direct link between the action of hydraulically fracturing the well itself and contamination of groundwater resources. The study report does not, therefore, appear to provide a reasonable basis to expect Congress to repeal the exemption for hydraulic fracturing under the SDWA at the federal level.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the Railroad Commission of Texas issued a "well integrity rule," which updates the requirements for drilling, putting pipe down and cementing wells. The rule includes testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water, including saltwater, gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies recently have focused on a possible connection between hydraulic fracturing related activities and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In addition, a number of lawsuits have been filed in other states, for example recent lawsuits in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements on the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in October 2014, the Railroad Commission of Texas published a rule governing permitting or re-permitting of disposal wells that would 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 for a disposal well permit fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates that such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well. The Oklahoma Corporation Commission also released well completion seismicity guidelines in December 2016 for operators in the SCOOP and STACK that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. In addition, in February 2017, the Oklahoma Corporation Commission's Oil and Gas Conservation Division issued an order limiting future increases in the volume of oil and natural gas wastewater injected into the ground in an effort to reduce the number of earthquakes in the state. It is possible that similar measures could be implemented in the areas where we operate.

We dispose of large volumes of produced water, including saltwater, gathered from our drilling and production operations using disposal wells pursuant to permits issued by governmental authorities overseeing such disposal activities and pursuant to permissions granted by the owners of properties where the disposal wells are located. While these permits are issued in accordance with existing laws and regulations, these legal requirements are subject to change, as are the permissions granted by property owners. Any changes could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities or property owners regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations or changes that restrict our expected ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities, either by limiting disposal volumes, disposal well locations or otherwise, or requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil or natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect our operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. On May 2, 2018, J.A. (Alan) Townsend, our President and Chief Executive Officer, informed our board of directors of his intent to retire from his position as President and Chief Executive Officer and as a director of the Company. Mr. Townsend continued to serve in his capacity as Director, President and Chief Executive Officer until September 4, 2018, at which point Gary C. Hanna, the Chairman of our board of directors, was appointed interim President and Chief Executive Officer while the Company searches for a permanent replacement. On March 11, 2019, we announced the hiring of David L. French to succeed Gary C. Hanna as our President and Chief Executive Officer. Loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

Our business is difficult to evaluate because it may be susceptible to the potential difficulties associated with rapid growth and expansion.

Our assets have grown rapidly over the last several years. We believe that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burden;
- increased capital requirements; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information contained in this Annual Report on Form 10-K is not necessarily indicative of the results that may be realized in the future.

We identified material weaknesses in our internal control over financial reporting in the prior year and may identify additional material weaknesses in the future or otherwise fail to maintain an effective system of internal controls, which may result in material misstatements of our financial statements or cause us to fail to meet our periodic reporting obligations.

We are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002 (“Sarbanes-Oxley Act”). Section 404 requires that we document and test our internal control over financial reporting and issue management’s assessment of our internal control over financial reporting. In our annual report for the year ended December 31, 2017, we identified and disclosed material weaknesses related to the lack of sufficient qualified accounting personnel and inadequately designed accounting processes, which led to the incorrect application of generally accepted accounting principles, ineffective controls over accounting for non-routine and/or complex transactions, and ineffective controls over the financial statement close and reporting processes. To remediate the material weaknesses, we have recruited technical accounting and finance personnel and have made significant advancements to our processes and internal controls surrounding non-routine and complex arrangements to strengthen our financial reporting processes. Based on testing performed by management, we believe the implemented controls are operating effectively and the prior year material weaknesses have been remediated as of December 31, 2018.

If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our Class A Common Stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters.

We have regularly sold non-core assets in order to increase capital resources available for other core assets and to create organizational and operational efficiencies. We have also occasionally sold interests in core assets for the purpose of accelerating the development and increasing efficiencies in such core assets. Various factors could materially affect our ability to dispose of such assets in the future, including the approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the assets with terms we deem acceptable.

Sellers often retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or of the indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

The standardized measure of our estimated proved reserves and our PV-10 are not necessarily the same as the current market value of our estimated proved oil, natural gas and NGL reserves.

The present value of future net cash flow from our proved reserves, or standardized measure, and our related PV-10 calculation, may not represent the current market value of our estimated proved oil, natural gas and NGL reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with the Financial Accounting Standard Board Codification 932, “Extractive Activities-Oil and Gas,” may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Our ability to use net operating loss carryforwards to offset future taxable income for U.S. federal income tax purposes is subject to limitation.

As of December 31, 2018, we have approximately $38.1 million of U.S. federal operating loss carryforwards (“NOLs”), which will begin to expire in 2035. Utilization of these NOLs depends on many factors, including our future income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (“Section 382”), generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an “ownership change” (as determined under Section 382). An ownership change generally occurs if one or more shareholders (or a group of shareholders) who are each deemed to own at least 5% of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage during a rolling three-year period.

In the event that an ownership change has occurred, or were to occur, utilization of our NOLs in existence at the time of the ownership change would be subject to an annual limitation under Section 382, determined by multiplying the value of our stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, subject to certain adjustments. Any unused annual limitation may be carried over to later years until they expire.

We believe we experienced an ownership change as a result of the Transaction on April 27, 2017, and our NOLs at the time of the Transaction are subject to limitation under Section 382 of the Code, which may cause U.S. federal income taxes to be paid earlier than otherwise would be paid if such limitation were not in effect and could cause such NOLs to expire unused, in each case reducing or eliminating the benefit of such NOLs. To the extent we are not able to offset our future income with our NOLs, this would adversely affect our operating results and cash flows if we attain profitability. Similar rules and limitations may apply for state income tax purposes.

We depend on computer and telecommunications systems and failures in our systems or cyber security attacks could significantly disrupt our business operations.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data, analyze seismic and drilling information, conduct reservoir modeling and reserves estimation, communicate with employees and business associates, perform compliance reporting and in many other activities related to our business. Our business associates, including vendors, service providers, purchasers of our production and financial institutions, are also dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. Our technologies, systems, networks and those of our business associates may become the target of cyber-attacks or information security breaches, which could lead to disruptions in critical systems, unauthorized release of confidential or protected information, corruption of data or other disruptions of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related business associates, including vendors, and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties to our computing and communications infrastructure or our information systems could significantly disrupt our business operations. A cyber-attack involving our information systems and related infrastructure, or that of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including;

- unauthorized access to seismic data, reserves information, strategic information or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and natural gas resources;
- unauthorized access to personal identifying information of royalty owners, partners, employees and vendors, which could expose us to allegations that we did not sufficiently protect that information;
- data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
- a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects; and
- a cyber-attack on a third party gathering, pipeline or rail service provider could delay or prevent us from marketing our production, resulting in a loss of revenues.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability, which could have a material adverse effect on our financial condition, results of operations or cash flows.

To date we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Our derivative transactions expose us to counterparty credit risk.

Our derivative transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas and natural gas liquids production, we have entered into oil, natural gas and natural gas liquids price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile commodity prices, such transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production; or
- the counterparties to our hedging agreements fail to perform under the contracts.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production. On July 21, 2010, then President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the SEC and the Commodity Futures Trading Commission ("CFTC"), along with other federal agencies, to promulgate regulations implementing the new legislation.

The CFTC has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin, clearing and trade execution; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the CFTC has re-proposed regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are expected to be made exempt from these limits. Also, it is possible that under recently adopted margin rules, some registered swap dealers may require us to post initial and variation margins in connection with certain swaps not subject to central clearing.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing commodity derivative contracts. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the implementing regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

Future regulations relating to and interpretations of recently enacted U.S. federal income tax legislation may vary from our current interpretation of such legislation.

The U.S. federal income tax legislation recently enacted in Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), is highly complex and subject to interpretation. The presentation of our financial condition and results of operations is based upon our current interpretation of the provisions contained in the Tax Act. In the future, the Treasury Department and the Internal Revenue Service are expected to release regulations relating to and interpretive guidance of the legislation contained in the Tax Act. Any significant variance of our current interpretation of such legislation from any future regulations or interpretive guidance could result in a change to the presentation of our financial condition and results of operations and could negatively affect our business.

Changes to state tax laws in response to recently enacted U.S. federal tax legislation.

Currently, many states conform their calculation of corporate taxable income to the calculation of corporate taxable income at the U.S. federal level. Due to recently enacted changes to U.S. federal income tax laws, certain states may change or modify the calculation of corporate taxable income at the state level. Any resulting increase in costs due to such changes could have an adverse effect on our financial position, results of operations and cash flows.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, seismicity, oil spills and explosions of natural gas transmission lines, may lead to regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

Risks Related to Our Indebtedness

We may incur substantial additional debt, which could decrease our ability to maintain operations or service existing debt obligations.

Subject to the restrictions in our Amended and Restated Credit Agreement, Series B Certificate of Designation and the Note Purchase Agreement (as defined below), we may incur substantial additional debt in the future. We may also consider investments in joint ventures or acquisitions that may increase our indebtedness. Adding new debt to then existing debt levels could intensify the operational risks that we now face.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on, or to refinance, our indebtedness obligations, including our Amended and Restated Credit Agreement and $100 million aggregate principal amount of 10.00% Senior Secured Lien Notes issued on December 8, 2017 (the "Second Lien Notes"), depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our current and future indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our Amended and Restated Credit Agreement, Series B Certificate of Designation and the Note Purchase Agreement restrict, among other things, our ability to dispose of assets and our use of the proceeds from such disposition. See "Restrictions in our Amended and Restated Credit Agreement, Certificate of Designation for the Series B. Preferred Stock and the Note Purchase Agreement limit, and our future debt agreements could limit, our ability to engage in certain activities."

Preferred Stock and the Note Purchase Agreement limit, and our future debt agreements could limit, our ability to engage in certain activities. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

Restrictions in our Amended and Restated Credit Agreement, Certificate of Designation for the Series B Preferred Stock and the Note Purchase Agreement limit, and our future debt agreements could limit, our ability to engage in certain activities.

Our Amended and Restated Credit Agreement, Series B Certificate of Designation and the Note Purchase Agreement contain, and our future debt agreements may contain, a number of significant covenants, including restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- be liable in respect of any third-party guaranty;
- incur liens;
- make loans to others;
- make investments;
- pay dividends or make distributions to third parties;
- liquidate, merge or consolidate with another entity;

- enter into commodity hedges exceeding a specified percentage of our expected production;

- enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness;

- sell properties or assets;

- issue additional shares of capital stock; and

- engage in certain other transactions without the prior consent of the holders of the Second Lien Notes, the Series B Preferred Stock and/or JPMorgan Chase Bank, N.A. and the lenders under the Amended and Restated Credit Agreement.

In addition, our Amended and Restated Credit Agreement requires us to maintain the following financial ratios: (1) a current ratio, which is the ratio of consolidated current assets (including unused commitments under the Amended and Restated Credit Agreement, but excluding non-cash assets) to consolidated current liabilities (excluding non-cash obligations, reclamation obligations to the extent classified as current liabilities and current maturities under the Amended and Restated Credit Agreement), of not less than 1.0 to 1.0, and (2) a leverage ratio, which is the ratio of the sum of all of our Total Debt to Annualized EBITDAX (as such terms are defined in the Amended and Restated Credit Agreement) for the four fiscal quarters (or other applicable period) then ended, of not greater than 4.00 to 1.00 and (3) a coverage ratio, which is the ratio of (i) EBITDAX (as defined in the Amended and Restated Credit Agreement) to (ii) the sum of (x) Interest Expense (as such terms are defined in the Amended and Restated Credit Agreement) plus (y) the aggregate amount of Restricted Payments made in cash pursuant to Sections 9.04(a)(iv) and (v) of the Amended and Restated Credit Agreement, during the preceding four fiscal quarters, of not less than 2.5 to 1.0. Failure to do so could result in mandatory or full repayment of the indebtedness. The senior secured credit facility also does not permit us to borrow funds if at the time of such borrowing, we are not in pro forma compliance with the financial covenants.

Although as of December 31, 2018 we were in compliance with the current ratio covenant, if we do not sufficiently reduce our capital expenditures in the future or obtain additional financing prior to our next borrowing base redetermination date, we may be required to seek a waiver from our lenders with respect to our compliance with our current ratio covenant. There can be no assurance that the lenders will grant a waiver. Our next scheduled redetermination date is April 1, 2019, although we have the right to request a redetermination prior to that date.

A breach of any covenant in our Amended and Restated Credit Agreement, including the current ratio covenant, likely would result in a default under the Amended and Restated Credit Agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under our Amended and Restated Credit Agreement and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness may become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us. If an event of default occurs under the Amended and Restated Credit Agreement, JPMorgan Chase Bank, N.A. will have the right to proceed against the pledged capital stock and take control of substantially all of our material operating subsidiaries that are guarantors' assets. The results of such action would have a significant negative impact on our results of operations and financial condition.

If we fail to pay dividends on the Series B Preferred Stock in any fiscal quarter, the dividend rate will increase from 10% to 12% per annum on the $1,000 liquidation preference per share of Series B Preferred Stock until such dividends are paid in full. In addition, if the Company fails to pay dividends for three out of four consecutive fiscal quarters or for six quarters (whether or not consecutive), then a representative appointed by the holders of a majority of the outstanding shares of Series B Preferred Stock shall have the right to appoint one director to our board of directors, and we shall be required to seek the approval of such representative for certain corporate actions, in each case, until three months following the date on which such dividends are paid in full.

The restrictions in our Amended and Restated Credit Agreement, Series B Certificate of Designation and the Note Purchase Agreement limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our Amended and Restated Credit Agreement, Series B Certificate of Designation and the Note Purchase Agreement impose on us.

Any significant reduction in the borrowing base under our Amended and Restated Credit Agreement as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our Amended and Restated Credit Agreement limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine at certain periods throughout the year. The borrowing base depends on, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing our loan. If we do not furnish the information required for the redetermination by the specified date, the lender may nonetheless redetermine the borrowing base in their sole discretion until the relevant information is received.

In the future, we may not be able to access adequate funding under our Amended and Restated Credit Agreement (or a replacement facility) as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Our Amended and Restated Credit Agreement is subject to similar or greater interest rate expenses. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve planned growth and operating results.

Uncertainty about the future of the London Interbank Offer Rate ("LIBOR") may adversely affect our business and financial results.

LIBOR meaningfully influences market interest rates around the globe. In July 2017, the Chief Executive of the United Kingdom Financial Conduct Authority, which regulates LIBOR, announced its intent to stop persuading or compelling banks to submit rates for the calculation of LIBOR to the administrator of LIBOR after 2021. This announcement indicates that the continuation of LIBOR as currently constructed is not guaranteed after 2021. It is impossible to predict whether and to what extent banks will continue to provide LIBOR submissions to the administrator of LIBOR, whether any additional reforms to LIBOR may be enacted in the United Kingdom or elsewhere, and whether other rate or rates may become accepted alternatives to LIBOR.

In 2014, the Federal Reserve Board and the Federal Reserve Bank of New York convened the Alternative Reference Rates Committee ("ARRC") to identify best practices for alternative reference rates, identify best practices for contract robustness, develop an adoption plan, and create an implementation plan with metrics of success and a timeline. The ARRC accomplished its first set of objectives and has identified the Secured Overnight Financing Rate ("SOFR") as the rate that represents best practice for use in certain new U.S. dollar derivatives and other financial contracts. The ARRC also published its Paced Transition Plan, with specific steps and timelines designed to encourage adoption of the SOFR. The ARRC was reconstituted in 2018 to help to ensure the successful implementation of the Paced Transition Plan and serve as a forum to coordinate and track planning across cash and derivatives products and market participants currently using LIBOR.

No assurance can be provided that the uncertainties around LIBOR or their resolution will not adversely affect the use, level and volatility of LIBOR or other interest rates or the value of LIBOR-based securities or other securities or financial arrangements. Further, the viability of SOFR as an alternative reference rate and the availability and acceptance of other alternative reference rates are unclear and also may have adverse effects on market rates of interest and the value of securities and other financial arrangements. These uncertainties, proposals and actions to resolve them, and their ultimate resolution also could negatively impact our funding costs, loan and other asset values, asset-liability management strategies, and other aspects of our business and financial results. We will monitor the continuous emergence of SOFR, as it could adversely impact our interest rate risk, and therefore the amount of interest we pay on liabilities currently measured at LIBOR.

Risks Related to the Class A Common Stock and Our Capital Structure

We are a holding company. Our sole material asset is our equity interest in Rosehill Operating and we are accordingly dependent upon distributions from Rosehill Operating to pay taxes, make payments under the Tax Receivable Agreement, cover our corporate and other overhead expenses and make payments with respect to our Series A Preferred Stock and Series B Preferred Stock.

We are a holding company and have no material assets other than our equity interest in Rosehill Operating. We have no independent means of generating revenue. To the extent Rosehill Operating has available cash, we intend to cause Rosehill Operating to make (i) generally pro rata distributions to its unitholders, including us, in an amount at least sufficient to allow us to pay dividends with respect to the Series A Preferred Stock and the Series B Preferred Stock, pay our taxes and to make payments under the Tax Receivable Agreement with Tema and (ii) non-pro rata payments to us to reimburse us for our corporate and other overhead expenses. To the extent that we need funds and Rosehill Operating or its subsidiaries are restricted from making such distributions or payments under applicable law or regulation or under the terms of any financing arrangements, or are otherwise unable to provide such funds, our liquidity and financial condition could be materially adversely affected.

The market price of the Class A Common Stock may decline.

Fluctuations in the price of the Class A Common Stock could contribute to the loss of all or part of your investment. The trading price of the Class A Common Stock could be volatile and subject to wide fluctuations in response to various factors, some of which are beyond our control. Any of the factors listed below could have a material adverse effect on your investment and the Class A Common Stock may trade at prices significantly below the price you paid for them. In such circumstances, the trading price of the Class A Common Stock may not recover and may experience a further decline.

Factors affecting the trading price of the Class A Common Stock may include:

- actual or anticipated fluctuations in our quarterly financial results or the quarterly financial results of companies perceived to be similar to us;
- changes in the market's expectations about our operating results;
- success of competitors;
- our operating results failing to meet the expectation of securities analysts or investors in a particular period;
- changes in financial estimates and recommendations by securities analysts concerning us or our markets in general;
- operating and stock price performance of other companies that investors deem comparable to us;
- changes in laws and regulations affecting our business;
- commencement of, or involvement in, litigation involving us, or developments in such litigation;
- changes in our capital structure, such as future issuances of securities or the incurrence of additional debt;
- the volume of securities available for public sale;
- any major change in our board or management;
- sales of substantial amounts of our securities by our directors, executive officers or significant stockholders or the perception that such sales could occur; and
- general economic and political conditions such as recession; interest rate, fuel price and international currency fluctuations; and acts of war or terrorism.

Many of the factors listed above are beyond our control. In addition, broad market and industry factors may materially harm the market price of the Class A Common Stock irrespective of our operating performance. The stock market in general and NASDAQ have experienced price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of the particular companies affected. The trading prices and valuations of our Class A Common Stock and Public

Warrants, which trade on The NASDAQ Capital Market, may not be predictable. A loss of investor confidence in the market for retail stocks or the stocks of other companies which investors perceive to be similar to us could depress the price of the Class A Common Stock regardless of our business, prospects, financial conditions or results of operations. A decline in the market price of the Class A Common Stock also could adversely affect our ability to issue additional securities and our ability to obtain additional financing in the future.

If securities or industry analysts do not publish or cease publishing research or reports about us, our business, or our market, or if they change their recommendations regarding the Class A Common Stock adversely, the price and trading volume of the Class A Common Stock could decline.

The trading market for the Class A Common Stock relies in part on the research and reports that industry or financial analysts publish about us or our business. We do not control these analysts and there can be no assurance that any will cover us in the future. Furthermore, if one or more analysts do cover us and downgrade or provide negative outlook on our stock or our industry, or the stock of any of our competitors, or publishes inaccurate or unfavorable research about our business, the price of the Class A Common Stock could decline. If one or more of these analysts commence and subsequently cease coverage of our business or fail to publish reports on us regularly, we could lose visibility in the market, which in turn could cause our stock price or trading volume to decline.

Tema and KLR Energy Sponsor, LLC ("KLR Sponsor") own a significant percentage of our outstanding voting common stock.

Tema and KLR Sponsor currently beneficially own approximately 71.5% of our voting common stock and, upon the conversion of our Series A Preferred Stock, will beneficially own approximately 62.9% of our voting common stock. As long as Tema and KLR Sponsor own or control a significant percentage of outstanding voting power, they will continue to have the ability to strongly influence all corporate actions requiring stockholder approval, including the election and removal of directors and the size of our board of directors, any amendment of our charter or bylaws, or the approval of any merger or other significant corporate transaction, including a sale of substantially all of our assets.

The interests of Tema and KLR Sponsor may not align with the interests of our other stockholders. Tema and KLR Sponsor may acquire and hold interests in businesses that compete directly or indirectly with us. Tema and KLR Sponsor may also pursue acquisition opportunities that may be complementary to our business, and, as a result, those acquisition opportunities may not be available to us. In addition, our second amended and restated certificate of incorporation (the "certificate of incorporation"), amended and restated bylaws and the Shareholders' and Registration Rights Agreement, dated as of December 20, 2016, by and among the Company, Tema, KLR Sponsor, Anchorage Illiquid Opportunities V, L.P. and AIO V AIV 3 Holdings, L.P. (the "SHRRA"), provide that, subject to certain limitations, we renounce any interest or expectancy in the business opportunities of our officers and directors and their respective affiliates and each such party shall not have any obligation to offer us those opportunities unless presented to one of our directors or officers in his or her capacity as a director or officer.

We are currently a "controlled company" within the meaning of the NASDAQ listing rules, but may not retain that status in the event that we conduct equity offerings in the future. However, during the phase-in period we may continue to rely on exemptions from certain corporate governance requirements that provide protection to stockholders of other companies.

Because Tema and KLR Sponsor control a majority of the combined voting power of all classes of our outstanding voting stock, we have been a "controlled company" under NASDAQ corporate governance listing standards. Under the NASDAQ rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NASDAQ corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the nominating and governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

In the event that we conduct equity offerings in the future, Tema and KLR Sponsor may cease to control a majority of the combined voting power of all classes of our outstanding voting stock. Accordingly, we may no longer be a "controlled company" within the meaning of the rules of NASDAQ. Under NASDAQ rules, a company that ceases to be a controlled company must comply with the independent board committee requirements as they relate to the nominating and corporate governance and compensation committees on the following phase-in schedule: (1) one independent committee member at the time it ceases to be a controlled company, (2) a majority of independent committee members within 90 days of the date it ceases to be a controlled company and (3) all independent committee members within one year of the date it ceases to be a controlled company. Additionally, NASDAQ rules provide a 12-month phase-in period from the date a company ceases to be a controlled company to comply with the majority independent board requirement. During these phase-in periods, our stockholders will not have the same protections afforded to stockholders of companies of which the majority of directors are independent. Additionally, if, within the phase-in periods, we are not able to recruit additional directors who would qualify as independent, or otherwise comply with NASDAQ rules, we may be subject to enforcement actions by NASDAQ. Furthermore, a change in our board of directors and committee membership may result in a change in corporate strategy and operation philosophies, and may result in deviations from our current growth strategy.

The pro forma per share data included in this Annual Report on Form 10-K excludes the transaction costs attributable to the Transaction and may not be indicative of what our actual financial position or results of operations would have been had the Transaction not occurred.

We incurred non-recurring transaction costs that were directly attributable to the Transaction of$2.6 million and $2.8 million for the years ended December 31, 2017 and 2016, respectively. We did not incur any non-recurring transaction costs that were directly attributable to the Transaction in 2018. The pro forma per share data included in this Annual Report on Form 10-K was calculated excluding transaction costs attributable to the Transaction and is presented for illustrative purposes only. The pro forma per share data is not necessarily indicative of what our actual financial position or results of operations would have been had the Transaction not been completed on the dates indicated. See “Selected Financial Data.”

Future sales of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of Class A Common Stock or securities convertible into Class A Common Stock in subsequent public or private offerings. On December 31, 2018, 13,760,136 shares of our Class A Common Stock were outstanding.

Downward pressure on the market price of our Class A Common Stock that likely will result from sales of our Class A Common Stock issued in connection with the exercise of the warrants for shares of Class A Common Stock or the conversion of the Class B Common Stock or Series A Preferred Stock could encourage short sales of our Class A Common Stock by market participants. Generally, short selling means selling a security, contract or commodity not owned by the seller. The seller is committed to eventually purchase the financial instrument previously sold. Short sales are used to capitalize on an expected decline in the security’s price. Such sales of our Class A Common Stock could have a tendency to depress the price of the stock, which could increase the potential for short sales.

We cannot predict the size of future issuances of our Class A Common Stock or securities convertible into Class A Common Stock or the effect, if any, that future issuances and sales of shares of our Class A Common Stock will have on the market price of our Class A Common Stock. Sales of substantial amounts of our Class A Common Stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Shares of the Class A Common Stock are equity interests and are therefore subordinated to our indebtedness and preferred stock.

In the event of our liquidation, dissolution or winding up, the Class A Common Stock would rank below our Series A Preferred Stock and Series B Preferred Stock and all secured debt claims against us. As a result, holders of the Class A Common Stock will not be entitled to receive any payment or other distribution of assets upon our liquidation, dissolution or winding up until all of our obligations to our secured debt holders and to holders of our Series A Preferred Stock and Series B Preferred Stock have been satisfied.

The Series A Preferred Stock and the Series B Preferred Stock rank junior to all of our indebtedness and other liabilities.

In the event of our bankruptcy, liquidation, reorganization or other winding-up, our assets will be available to pay obligations on the Series A Preferred Stock and the Series B Preferred Stock only after all of our indebtedness and other liabilities have been paid. In addition, we are a holding company and the Series A Preferred Stock and the Series B Preferred Stock will effectively rank junior to all existing and future indebtedness and other liabilities (including trade payables) of our subsidiaries and any capital stock of our subsidiaries not held by us. The rights of holders of the Series A Preferred Stock and the Series B Preferred Stock to participate in the distribution of assets of our subsidiaries will rank junior to the prior claims of that subsidiary's creditors and any other equity holders. Consequently, if we are forced to liquidate our assets to pay our creditors, we may not have sufficient assets remaining to pay amounts due on any or all of the Series A Preferred Stock and the Series B Preferred Stock then outstanding. We and our subsidiaries may incur substantial amounts of additional debt and other obligations that will rank senior to the Series A Preferred Stock and the Series B Preferred Stock.

We are not obligated to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock if prohibited by law and will not be able to pay cash dividends if we have insufficient cash to do so.

Under Delaware law, dividends on capital stock may only be paid from "surplus" or, if there is no "surplus," from the corporation's net profits for the then-current or the preceding fiscal year. Unless we operate profitably, our ability to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock would require the availability of adequate "surplus," which is defined as the excess, if any, of our net assets (total assets less total liabilities) over our capital.

Further, even if adequate surplus is available to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock, we may not have sufficient cash to pay cash dividends on the Series A Preferred Stock and the Series B Preferred Stock. We may elect to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock in shares of additional Series A Preferred Stock or Series B Preferred Stock, as applicable; however, our ability to pay dividends in shares of our Series A Preferred Stock and Series B Preferred Stock may be limited by the number of shares of Series A Preferred Stock and Series B Preferred Stock we are authorized to issue under our certificate of incorporation. In the case of the Series B Preferred Stock, with respect to dividends declared for any quarter ending on or prior to January 15, 2019, the Company may elect to pay as dividends additional shares of Series B Preferred Stock in kind in an amount up to 40% of that which would have been payable had the dividends been fully paid in cash. As of December 31, 2018, we had 101,669 shares of Series A Preferred Stock outstanding and 156,746 shares of Series B Preferred Stock outstanding out of 1,000,000 authorized shares of preferred stock, 150,000 of which are designated as Series A Preferred Stock and 210,000 shares are designated as Series B Preferred Stock.

The terms of our financing agreements may limit our ability to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock.

Financing agreements, whether ours or those of our subsidiaries and whether in place now or in the future, may contain restrictions on our ability to pay cash dividends on our capital stock, including the Series A Preferred Stock and the Series B Preferred Stock. These limitations may cause us to be unable to pay cash dividends on the Series A Preferred Stock and the Series B Preferred Stock. For example, the Credit Agreement will restrict our ability to pay cash dividends unless certain criteria are met. Since we are not obligated to declare or pay cash dividends, we do not intend to do so to the extent we are restricted by any of our financing agreements.

The Series A Preferred Stock and the Series B Preferred Stock do not have an established trading market, which may negatively affect their market value and the ability to transfer or sell such shares.

The Series A Preferred Stock and the Series B Preferred Stock do not have an established trading market. Since the Series A Preferred Stock and the Series B Preferred Stock have no stated maturity date, investors seeking liquidity will be limited to selling their shares in the secondary market or, in the case of holders of Series A Preferred Stock, converting their shares and selling in the secondary market. We do not intend to list the Series A Preferred Stock and the Series B Preferred Stock on any securities exchange. We cannot make any assurances that an active trading market in the Series A Preferred Stock and the Series B Preferred Stock will develop or, even if it develops, we cannot assure that it will last. In either case, the trading price of the Series A Preferred Stock and the Series B Preferred Stock could be adversely affected and the ability of holders of our Series A Preferred Stock and Series B Preferred Stock to transfer their shares will be limited. We are not aware of any entity making a market in the shares of our Series A Preferred Stock or Series B Preferred Stock which we anticipate may further limit liquidity.

Upon conversion of the Series A Preferred Stock, holders may receive less valuable consideration than expected because the value of our Class A Common Stock may decline after such holders exercise their conversion right but before we settle our conversion obligation.

Under the Series A Preferred Stock, a converting holder will be exposed to fluctuations in the value of our Class A Common Stock during the period from the date such holder surrenders shares of Series A Preferred Stock for conversion until the date we settle our conversion obligation. Upon conversion, we will be required to deliver the shares of our Class A Common Stock, together with a cash payment for any fractional share, on the third business day following the relevant conversion date. Accordingly, if the price of our Class A Common Stock decreases during this period, the value of the shares of Class A Common Stock that holders of Series A Preferred Stock receive will be adversely affected and would be less than the conversion value of the Series A Preferred Stock on the conversion date.

The conversion rate of the Series A Preferred Stock may not be adjusted for all dilutive events.

The number of shares of our Class A Common Stock that holders of our Series A Preferred Stock are entitled to receive upon conversion of the Series A Preferred Stock is subject to adjustment for certain specified events, including, but not limited to, the issuance of certain stock dividends on our Class A Common Stock, the issuance of certain rights or warrants, subdivisions, combinations, distributions of capital stock, indebtedness, or assets, cash dividends and certain issuer tender or exchange offers, as set forth in the Certificate of Designation for the Series A Preferred Stock filed with the Secretary of State of the State of Delaware on April 27, 2017 ("Series A Certificate of Designation"). However, the conversion rate may not be adjusted for other events, such as the exercise of stock options held by our employees or offerings of our Class A Common Stock or securities convertible into Class A Common Stock (other than those set forth in the Series A Certificate of Designation) for cash or in connection with acquisitions, which may adversely affect the market price of our Class A Common Stock. Further, if any of these other events adversely affects the market price of our Class A Common Stock, we expect it to also adversely affect the market price of our Series A Preferred Stock. In addition, the terms of our Series A Preferred Stock do not restrict our ability to offer Class A Common Stock or securities convertible into Class A Common Stock in the future or to engage in other transactions that could dilute our Class A Common Stock. We have no obligation to consider the interests of the holders of our Series A Preferred Stock in engaging in any such offering or transaction. If we issue additional shares of Class A Common Stock, those issuances may materially and adversely affect the market price of our Class A Common Stock and, in turn, those issuances may adversely affect the trading price of the Series A Preferred Stock.

The additional shares of our Class A Common Stock deliverable for shares of Series A Preferred Stock converted in connection with a fundamental change may not adequately compensate holders of our Series A Preferred Stock.

If a "fundamental change" (as defined in the Series A Certificate of Designation) occurs, we will under certain circumstances increase the conversion rate by a number of additional shares of our Class A Common Stock for shares of Series A Preferred Stock converted in connection with such fundamental change as described in the Series A Certificate of Designation. While this feature is designed to, among other things, compensate holders of our Series A Preferred Stock for lost option time value of their shares of Series A Preferred Stock as a result of the fundamental change, it may not adequately compensate them for their loss as a result of such transaction.

In addition, holders of the Series A Preferred Stock will have no additional rights upon a fundamental change, and will have no right not to convert their shares of Series A Preferred Stock into shares of our Class A Common Stock. Any shares of Class A Common Stock such holders receive upon a fundamental change may be worth less than the liquidation preference per share of Series A Preferred Stock.

Our obligation to satisfy the additional shares requirement could be considered a penalty, in which case the enforceability thereof would be subject to general principles of reasonableness and equitable remedies.

In some limited circumstances, we may not have reserved a sufficient number of shares of our Class A Common Stock to issue the full amount of shares of Class A Common Stock issuable upon conversion following a fundamental change.

Some significant restructuring transactions may not constitute a fundamental change but may nevertheless result in holders of the Series A Preferred Stock being adversely affected.

Upon the occurrence of a "fundamental change" (as defined in the Series A Certificate of Designation), there may be an increase in the conversion rate as described in the Series A Certificate of Designation. However, these provisions will not afford protection to holders of Series A Preferred Stock in the event of other transactions that could adversely affect the value of the Series A Preferred Stock. For example, transactions such as leveraged recapitalizations, refinancings, restructurings, or acquisitions initiated by us may not constitute a fundamental change. In the event of any such transaction, holders would not have the protection afforded by the provisions applicable to a fundamental change even though each of these transactions could increase the amount of our indebtedness, or otherwise adversely affect our capital structure or any credit ratings, thereby adversely affecting the holders of Series A Preferred Stock.

Upon a conversion in connection with a fundamental change, holders of our Series A Preferred Stock may receive consideration worth less than the $1,000 liquidation preference per share of Series A Preferred Stock, plus any accumulated and unpaid dividends thereon.

If a "fundamental change" (as defined in the Series A Certificate of Designation) occurs, and regardless of the price paid (or deemed paid) per share of our Class A Common Stock in such fundamental change, then the conversion rate may be adjusted to increase the number of the shares of our Class A Common Stock deliverable upon conversion of each share of Series A Preferred Stock to the $1,000 liquidation preference per share of Series A Preferred Stock, *plus* any accumulated and unpaid dividends thereon. However, under certain circumstances, holders may receive a number of shares of Class A Common Stock worth less than the $1,000 liquidation preference per share of Series A Preferred Stock, *plus* any accumulated and unpaid dividends thereon. Holders of our Series A Preferred Stock have no claim against us for the difference between the value of the consideration they receive upon a conversion in connection with a fundamental change and the $1,000 liquidation preference per share of Series A Preferred Stock, *plus* any accumulated and unpaid dividends thereon.

We may issue additional series of preferred stock that rank equally to the Series A Preferred Stock and the Series B Preferred Stock as to dividend payments and liquidation preference.

Neither our certificate of incorporation, Series A Certificate of Designation nor Series B Certificate of Designation prohibit us from issuing additional series of preferred stock that would rank equally to the Series A Preferred Stock and the Series B Preferred Stock as to dividend payments and liquidation preference. Our certificate of incorporation, the Series A Certificate of Designation and the Series B Certificate of Designation provide that we have the authority to issue up to 1,000,000 shares of preferred stock, including up to 150,000 shares of Series A Preferred Stock and 210,000 shares of Series B Preferred Stock. The issuances of other series of preferred stock could have the effect of reducing the amounts available to the Series A Preferred Stock and the Series B Preferred Stock in the event of our liquidation, winding-up or dissolution. It may also reduce cash dividend payments on the Series A Preferred Stock and the Series B Preferred Stock if we do not have sufficient funds to pay dividends on all outstanding Series A Preferred Stock and Series B Preferred Stock and parity preferred stock.

Holders of our Series A Preferred Stock have no rights with respect to the shares of our Class A Common Stock underlying the Series A Preferred Stock until they convert their Series A Preferred Stock, but they may be adversely affected by certain changes made with respect to our Class A Common Stock.

Holders of our Series A Preferred Stock will have no rights with respect to the shares of our Class A Common Stock underlying their Series A Preferred Stock, including voting rights, rights to respond to Class A Common Stock tender offers, if any, and rights to receive dividends or other distributions on our Class A Common Stock, if any (in each case, other than through a conversion rate adjustment), prior to the conversion date with respect to a conversion of such holder's Series A Preferred Stock, but the investment in our Series A Preferred Stock may be negatively affected by these events. Upon conversion, holders of our Series A Preferred Stock will be entitled to exercise the rights of a holder of Class A Common Stock only as to matters for which the relevant record date occurs on or after the conversion date. For example, in the event that an amendment is proposed to our certificate of incorporation or bylaws requiring stockholder approval and the record date for determining the stockholders of record entitled to vote on the amendment occurs prior to the conversion date, holders of our Series A Preferred Stock will not be entitled to vote on the amendment, although they will nevertheless be subject to any changes in the powers, preferences or special rights of our Class A Common Stock.

Holders of our Series A Preferred Stock and Series B Preferred Stock will have no voting rights except under limited circumstances.

Except with respect to certain material and adverse changes to the Series A Preferred Stock and the Series B Preferred Stock as described in the Series A Certificate of Designation and the Series B Certificate of Designation, respectively, holders of our preferred stock do not have voting rights and have no right to vote for any members of our board of directors, except as may be required by Delaware law.

We may not have sufficient earnings and profits in order for distributions on the Series A Preferred Stock and the Series B Preferred Stock to be treated as dividends for U.S. federal income tax purposes.

Distributions payable by us on the Series A Preferred Stock and the Series B Preferred Stock may exceed our current and accumulated earnings and profits, as calculated for U.S. federal income tax purposes. To the extent that the amount of a distribution with respect to our Series A Preferred Stock or Series B Preferred Stock exceeds our current and accumulated earnings and profits, such distribution will be treated for U.S. federal income tax purposes as a return of capital and first be applied against and reduce the beneficial owner's adjusted tax basis in the Series A Preferred Stock or the Series B Preferred Stock, but not below zero. Any excess over such adjusted tax basis will be treated as capital gain. Such treatment will generally be unfavorable for corporate beneficial owners and may also be unfavorable to certain other beneficial owners.

Holders of our Series A Preferred Stock may be subject to tax if we make or fail to make certain adjustments to the conversion rate of the Series A Preferred Stock even though they do not receive a corresponding cash distribution.

The conversion rate of the Series A Preferred Stock is subject to adjustment in certain circumstances, including the payment of cash dividends. If the conversion rate is adjusted as a result of a distribution that is taxable to our common stockholders, such as a cash dividend, holders of our Series A Preferred Stock may be deemed to have received a dividend subject to U.S. federal income tax without the receipt of any cash. In addition, a failure to adjust (or to adjust adequately) the conversion rate after an event that increases the proportionate interest of the holders of Series A Preferred Stock in us could be treated as a deemed taxable dividend to such holders. If a "fundamental change" (as defined in the Series A Certificate of Designation) occurs, under some circumstances, we will increase the conversion rate for shares of Series A Preferred Stock converted in connection with such fundamental change. If a holder of the Series A Preferred Stock is not a non-U.S. holder (as defined below), any deemed dividend may be subject to U.S. federal withholding tax at a 30% rate, or such lower rate as may be specified by an applicable income tax treaty, which may be set off against subsequent payments on the Series A Preferred Stock.

A "non-U.S. holder" is a beneficial owner of our common stock that is not for U.S. federal income tax purposes a partnership or any of the following: (i) an individual who is a citizen or resident of the United States; (ii) a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia; (iii) an estate the income of which is subject to U.S. federal income tax regardless of its source; or (iv) a trust (i) the administration of which is subject to the primary supervision of a U.S. court and which has one or more United States persons who have the authority to control all substantial decisions of the trust or (ii) which has made a valid election under applicable U.S. Treasury regulations to be treated as a United States person.

If a holder of our Series A Preferred Stock is a non-U.S. holder, dividends on our Series A Preferred Stock that are paid in shares may be subject to U.S. federal withholding tax in the same manner as a cash dividend, which the withholding agent might satisfy through a sale of a portion of the shares such holder receives as a dividend or through withholding of other amounts payable to such holder.

We may elect to pay dividends on our Series A Preferred Stock in shares of Series A Preferred Stock rather than in cash. Any such stock dividends paid to a holder of our Series A Preferred Stock will be taxable in the same manner as cash dividends and, if such holder is a non-U.S. holder, may be subject to U.S. federal withholding tax at a 30% rate, or such lower rate as may be specified by an applicable income tax treaty. Any required withholding tax might be satisfied by the withholding agent through a sale of a portion of the shares holders of our Series A Preferred Stock receive as a dividend or might be withheld from cash dividends or sales proceeds subsequently paid or credited to such holders.

Non-U.S. holders of our Series A Preferred Stock, Series B Preferred Stock or our Class A Common Stock could, in certain situations, be subject to U.S. federal income tax upon a sale, exchange, conversion or other disposition of such stock.

We believe that we are a "United States real property holding corporation" and likely will remain one in the foreseeable future. As a result, non-U.S. holders that own (or are treated as owning under constructive ownership rules) more than a specified amount of our Series A Preferred Stock, Series B Preferred Stock or our Class A Common Stock during a specified time period may be subject to U.S. federal income tax on a sale, exchange, conversion or other disposition of such stock and may be required to file a U.S. federal income tax return.

Because we currently have no plans to pay cash dividends on our Class A Common Stock, you may not receive any return on investment unless you sell your Class A Common Stock for a price greater than that which you paid for it.

We currently do not expect to pay any cash dividends on our Class A Common Stock. Any future determination to pay cash dividends or other distributions on our Class A Common Stock will be at the discretion of the board of directors and will be dependent on our earnings, financial condition, results of operations, capital requirements and contractual, regulatory and other restrictions, including restrictions contained in the senior secured credit facility or agreements governing any existing and future outstanding indebtedness we or our subsidiaries may incur, on the payment of dividends by us or by our subsidiaries to us, and other factors that our board of directors deems relevant.

As a result, you may not receive any return on an investment in our Class A Common Stock unless you sell shares of Class A Common Stock for a price greater than that which you paid for it.

Some of our total outstanding shares are restricted from immediate resale but may be sold into the market in the future. This could cause the market price of our Class A Common Stock to drop significantly, even if our business is doing well.

As of December 31, 2018, KLR Sponsor and Tema held approximately 71.5% of our issued and outstanding shares of Class A Common Stock, including Class A Common Stock issuable upon exchange of Class B Common Stock. The SHRRA restricts, except in certain circumstances, KLR Sponsor, Tema and permitted transferees from transferring 67% of their common stock until two years following the date of consummation of the Transaction. The market price of our Class A Common Stock could decline if the holders of previously restricted shares sell them or are perceived by the market as intending to sell them. Additionally, the Tax Receivable Agreement grants Tema the right to prevent certain dispositions of the assets we acquired in the Transaction for a period of up to three years following the closing of the Transaction.

Additionally, in connection with the Transaction, we issued a total of95,000 shares of Series A Preferred Stock (convertible into Class A Common Stock) and 9,000,000 warrants (exercisable for shares of Class A Common Stock), and have a total of 25,594,158 warrants outstanding at December 31, 2018. To the extent the Class A Common Stock that is issuable upon conversion or exercise of these securities is sold, the market price of our Class A Common Stock could decline.

Holders of our Series B Preferred Stock have certain limited consent rights that could prevent us from taking certain corporate actions, and as a result may adversely affect our business, operating results and stock price.

Holders of our Series B Preferred Stock have certain limited consent rights with respect to our ability to take certain corporate actions, including the following:

- the issuance, authorization or creation of any class or series of stock senior to or on par with the Series B Preferred Stock;
- the incurrence of additional indebtedness, provided that such indebtedness may be incurred if, after giving pro forma effect to the incurrence and any application of the proceeds thereof, we maintain a Leverage Ratio (as defined in the Series A Certificate of Designation) of less than 4.00 to 1.00;
- the issuance or incurrence of high-yield debt, unless the debt (A) does not have an all-in interest rate together with any component of yield greater than the Second Lien Notes (as defined below) and a make-whole provision less favorable than the Second Lien Notes and (B) is used to refinance the Second Lien Notes;
- the entry into any joint venture agreement or issuance of equity securities of our subsidiaries, other than to us or our wholly-owned subsidiaries;
- sales of certain property having a fair market value greater than $15.0 million in any fiscal year and $40.0 million in the aggregate;
- and certain property acquisitions or investments in excess of $15.0 million in any fiscal year and $40.0 million in the aggregate, unless such acquisitions or investments are financed solely using our common equity (or cash proceeds of the issuance of our common equity).

The consent rights of the holders of our Series B Preferred Stock could prevent us from obtaining future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities, and as a result may adversely affect our business, operating results and stock price.

Anti-takeover provisions contained in our certificate of incorporation and bylaws, as well as provisions of Delaware law, could impair a takeover attempt.

Our certificate of incorporation and bylaws contain provisions that may discourage unsolicited takeover proposals that stockholders may consider to be in their best interests. We are also subject to anti-takeover provisions under Delaware law, which could delay or prevent a change of control. Together these provisions may make more difficult the removal of management and may discourage transactions that otherwise could involve payment of a premium over prevailing market prices for our securities. These provisions include:

- a staggered board providing for three classes of directors, which limits the ability of a stockholder or group to gain control of our board;

- no cumulative voting in the election of directors, which limits the ability of minority stockholders to elect director candidates;

- the right of our board of directors to elect a director to fill a vacancy created by the expansion of the board of directors or the resignation, death, or removal of a director in certain circumstances, which prevents stockholders from being able to fill vacancies on our board of directors;

- the ability of our board of directors to determine whether to issue shares of our preferred stock and to determine the price and other terms of those shares, including preferences and voting rights, without stockholder approval, which could be used to significantly dilute the ownership of a hostile acquirer;

- the ability of each of Tema or KLR Sponsor to call a special meeting of stockholders, provided that such person owns 15% or more of the outstanding shares of common stock until the Trigger Date, and thereafter prohibit such ability;

- a prohibition on stockholders calling a special meeting upon and following the Trigger Date, which forces stockholder action to be taken at an annual or special meeting of our stockholders called by the board;

- the requirement that a meeting of stockholders may be called only by the board of directors after the Trigger Date, which may delay the ability of our stockholders to force consideration of a proposal or to take action, including the removal of directors;

- providing that after the Trigger Date directors may be removed prior to the expiration of their terms by stockholders only for cause or upon the affirmative vote of 75% of the voting power of all outstanding shares of the combined company;

- a requirement that changes or amendments to the certificate of incorporation or the bylaws must be approved (i) before the Trigger Date, by a majority of the voting power of outstanding common stock of the combined company, which such majority shall include at least 80% of the shares then held by KLR Sponsor and Tema, and (ii) thereafter, certain changes or amendments must be approved by at least 75% of the voting power of outstanding common stock of the combined company; and

- advance notice procedures that stockholders must comply with in order to nominate candidates to our board of directors or to propose matters to be acted upon at a stockholders' meeting, which may discourage or deter a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to obtain control of the Company.

Changes in laws or regulations, or a failure to comply with any laws and regulations, may adversely affect our business, investments and results of operations.

We are subject to laws, regulations and rules enacted by national, regional and local governments and NASDAQ. In particular, we are required to comply with certain SEC, NASDAQ and other legal or regulatory requirements. Compliance with, and monitoring of, applicable laws, regulations and rules may be difficult, time consuming and costly. Those laws, regulations and rules and their interpretation and application may also change from time to time and those changes could have a material adverse effect on our business, investments and results of operations. In addition, a failure to comply with applicable laws, regulations and rules, as interpreted and applied, could have a material adverse effect on our business and results of operations.

We may be required to make payments under the Tax Receivable Agreement for certain tax benefits that we may claim, and the amounts of such payments could be significant.

In connection with the closing of the Transaction, we entered into the Tax Receivable Agreement with Tema. This agreement generally provides for the payment by us to Tema of 90% of the net cash savings, if any, in U.S. federal, state and local income tax and franchise tax that we actually realize (computed using simplifying assumptions to address the impact of state and local taxes) or are deemed to realize in certain circumstances in periods after the Transaction as a result of certain increases in the tax basis in the assets of Rosehill Operating and certain benefits attributable to imputed interest. We will retain the benefit of the remaining 10% of these cash savings.

The term of the Tax Receivable Agreement will continue until all tax benefits that are subject to the Tax Receivable Agreement have been utilized or expired, unless we exercise our right to terminate the Tax Receivable Agreement early within thirty (30) days of certain mergers or other changes of control (or the Tax Receivable Agreement is terminated early due to our breach of a material obligation thereunder), and we make the termination payment specified in the Tax Receivable Agreement. In addition, payments we make under the Tax Receivable Agreement will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return.

The payment obligations under the Tax Receivable Agreement are our obligations and not obligations of Rosehill Operating, and we expect that the payments we will be required to make under the Tax Receivable Agreement will be substantial. Estimating the amount and timing of payments that may become due under the Tax Receivable Agreement is by its nature imprecise. For purposes of the Tax Receivable Agreement, cash savings in tax generally are calculated by comparing our actual tax liability (determined by using the actual applicable U.S. federal income tax rate and an assumed combined state and local income tax rate) to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the Tax Receivable Agreement. The actual increase in tax basis, as well as the amount and timing of any payments under the Tax Receivable Agreement, are dependent upon significant future events and assumptions, including the timing of the redemptions of Rosehill Operating Common Units, the price of our Class A Common Stock at the time of each redemption, the extent to which such redemptions are taxable transactions, the amount of Tema's tax basis in its Rosehill Operating Common Units at the time of the relevant redemption, the depreciation and amortization periods that apply to the increase in tax basis, the amount and timing of taxable income we generate in the future, the U.S. federal income tax rates then applicable, and the portion of our payments under the Tax Receivable Agreement that constitute imputed interest or give rise to depreciable or amortizable tax basis. The payments under the Tax Receivable Agreement will not be conditioned upon a holder of rights under the Tax Receivable Agreement having a continued ownership interest in us or Rosehill Operating.

In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the Tax Receivable Agreement.

If we elect to terminate the Tax Receivable Agreement early within thirty (30) days of certain mergers or other changes of control or it is terminated early due to our breach of a material obligation thereunder, our obligations under the Tax Receivable Agreement would accelerate and we would be required to make a substantial immediate lump-sum payment. This payment would equal the present value of the hypothetical future payments that could be required to be paid under the Tax Receivable Agreement (determined by applying a discount rate equal to the one-year London Interbank Offered Rate ("LIBOR") plus 150 basis points). The calculation of hypothetical future payments will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including (i) the assumption that we have sufficient taxable income to fully utilize the tax benefits covered by the Tax Receivable Agreement and (ii) the assumption that any Rosehill Operating Common Units (other than those held by us) outstanding on the termination date are deemed to be exchanged on the termination date. Any early termination payment may be made significantly in advance of the actual realization, if any, of the future tax benefits to which the termination payment relates.

Upon an early termination of the Tax Receivable Agreement, we could be required to make payments under the Tax Receivable Agreement that exceed our actual cash tax savings, if any, in respect of the tax attributes subject to the Tax Receivable Agreement. In these situations, our obligations under the Tax Receivable Agreement could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, or other forms of business combinations or changes of control. For example, if the Tax Receivable Agreement had been terminated at December 31, 2018, the estimated termination payments would, in the aggregate, have been approximately $71.9 million (calculated using a discount rate equal to one-year LIBOR plus 150 basis points, applied against an undiscounted liability of $101.3 million). The foregoing number is merely an estimate and the actual payments could differ materially. There can be no assurance that we will be able to finance our obligations under the Tax Receivable Agreement.

In the event that we elect to terminate the Tax Receivable Agreement early within thirty (30) days of certain mergers or other changes of control, the consideration payable to holders of our Class A Common Stock could be substantially reduced.

If we elect to terminate the Tax Receivable Agreement early within thirty (30) days of certain mergers or other changes of control, we would be obligated to make a substantial, immediate lump-sum payment, and such payment may be significantly in advance of, and may materially exceed, the actual realization, if any, of the future tax benefits to which the payment relates. As a result of this payment obligation, holders of our Class A Common Stock could receive substantially less consideration in connection with a change of control transaction than they would receive in the absence of such obligation. Further, our payment obligations under the Tax Receivable Agreement will not be conditioned upon Tema having a continued interest in us or Rosehill Operating. Accordingly, Tema's interests may conflict with those of the holders of our Class A Common Stock. Please read "In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits, if any, we realize, in respect of the tax attributes subject to the Tax Receivable Agreement" and "Certain Relationships and Related Party Transactions - Agreements Relating to the Transaction - Tax Receivable Agreement."

We will not be reimbursed for any payments made under the Tax Receivable Agreement in the event that any tax benefits are subsequently disallowed.

Payments under the Tax Receivable Agreement will be based on the tax reporting positions that we will determine. Tema will not reimburse us for any payments previously made under the Tax Receivable Agreement if any tax benefits that have given rise to payments under the Tax Receivable Agreement are subsequently disallowed, except that excess payments made to Tema will be netted against payments that would otherwise be made to Tema, if any, after our determination of such excess. As a result, in such circumstances, we could make payments that are greater than our actual cash tax savings, if any, and may not be able to recoup those payments, which could adversely affect our liquidity.

In certain circumstances, Rosehill Operating will be required to make tax distributions and tax advances to its unitholders, and the tax distributions and tax advances that Rosehill Operating will be required to make may be substantial.

Pursuant to the Second Amended LLC Agreement, Rosehill Operating will make generally pro rata cash distributions, or taxdistributions, to its unitholders, including us, in an amount sufficient to allow us to pay our taxes and to allow us to make payments under the Tax Receivable Agreement with Tema. In addition to these pro rata distributions, certain Rosehill Operating unitholders will be entitled to receive tax advances in an amount sufficient to allow each such unitholder to pay its respective taxes on such holder's allocable share of Rosehill Operating's taxable income. Any such tax advance will be calculated after taking into account certainother distributions or payments received by the unitholders from Rosehill Operating. Under the applicable tax rules, Rosehill Operating is required to allocate net taxable income disproportionately to its members incertain circumstances. Tax advances will be determined based on an assumed individual tax rate and will be repaid upon exercise of Tema's redemption right or the call right, as applicable.

Funds used by Rosehill Operating to satisfy its tax distribution and tax advance obligations will not be available for reinvestment in our business. Moreover, the tax distributions and tax advances Rosehill Operating will be required to make may be substantial, and because of the disproportionate allocation of net taxable income, may exceed the actual tax liability for some of the existing owners of Rosehill Operating.

The JOBS Act permits "emerging growth companies" like us to take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies.

We qualify as an "emerging growth company" as defined in the JOBS Act. As such, we take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies for as long as we continue to be an emerging growth company, including (i) the exemption from the auditor attestation requirements with respect to internal control over financial reporting under Section 404 of the Sarbanes-Oxley Act, (ii) the exemptions from say-on-pay, say-on-frequency and say-on-golden parachute voting requirements and (iii) reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements. As a result, our stockholders may not have access to certain information they deem important. We will remain an emerging growth company until the earliest of (i) the last day of the fiscal year following the fifth anniversary of the date of our initial public offering, (ii) the last day in the fiscal year in which we have total annual gross revenue of at least $1.07 billion (as adjusted for inflation pursuant to SEC rules from time to time), (iii) the date in which we are deemed to be a large accelerated filer, which means the market value of our Class A Common Stock that is held by non-affiliates exceeds $700 million as of the last business day of our prior second fiscal quarter, or (iv) the date on which we have issued more than $1.0 billion in non-convertible debt during the prior three-year period.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the exemption from complying with new or revised accounting standards provided in Section 7(a)(2)(B) of the Securities Act as long as we are an emerging growth company. An emerging growth company can therefore delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. The JOBS Act provides that a company can elect to opt out of the extended transition period and comply with the requirements that apply to non-emerging growth companies, but any such election to opt out is irrevocable. We have elected not to opt out of such extended transition period, which means that when a standard is issued or revised and it has different application dates for public or private companies, we, as an emerging growth company, can adopt the new or revised standard at the time private companies adopt the new or revised standard. This may make comparison of our financial statements with another public company which is neither an emerging growth company nor an emerging growth company which has opted out of using the extended transition period difficult or impossible because of the potential differences in accountant standards used.

We cannot predict if investors will find our Class A Common Stock less attractive because we will rely on these exemptions. If some investors find our Class A Common Stock less attractive as a result, there may be a less active trading market for our Class A Common Stock and our stock price may be more volatile.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties

Our properties are located within the Northern and Southern Delaware Basins, sub-basins of the Permian Basin. The Permian Basin consists of mature, legacy onshore oil and liquids-rich natural gas reservoirs that span approximately 86,000 square miles in West Texas and New Mexico. The Permian Basin is composed of five sub regions: the Delaware Basin, the Central Basin Platform, the Midland Basin, the Northwest Shelf and the Eastern Shelf. The Permian Basin is an attractive operating area due to its multiple horizontal and vertical target formations, favorable operating environment, high oil and liquids-rich natural gas content, mature infrastructure, well-developed network of oilfield service providers, long-lived reserves with consistent reservoir quality and historically high drilling success rates.

Oil and Natural Gas Reserves

Estimation and review of proved reserves

Proved reserve estimates as of December 31, 2018 were prepared by Netherland, Sewell & Associates, Inc. (“NSAI”) and proved reserve estimates as of December 31, 2017 and 2016 were prepared by Ryder Scott, L.P. (“Ryder Scott”), our independent petroleum engineers. NSAI and Ryder Scott do not own an interest in any of our properties, nor are they employed by us on a contingent basis. A copy of our independent petroleum engineer’s proved reserve report as of December 31, 2018 is attached as an exhibit to this Annual Report on Form 10-K.

NSAI is 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 persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Richard B. Talley and Mike K. Norton. Mr. Talley, a Licensed Professional Engineer in the State of Texas (No. 102425), has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. He graduated from the University of Oklahoma in 1998 with a Bachelor of Science Degree in Mechanical Engineering and from Tulane University in 2001 with a Master of Business Administration Degree. Mr. Norton, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441), has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Within Ryder Scott, the technical person primarily responsible for preparing the estimates set forth in the Ryder Scott reserves report is Val Rick Robinson, a Licensed Professional Engineer in the State of Texas. He graduated from Brigham Young University in 2003 with a Bachelor of Science Degree in Chemical Engineering. All technical principals meet or exceed 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; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

We maintain an internal staff of petroleum engineers and geoscience professionals to work closely with our independent petroleum engineers to ensure the integrity, accuracy and timeliness of the data used to calculate the proved reserves relating to our assets. Our internal technical team members meet with our independent petroleum engineers periodically to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to our independent petroleum engineers for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices, subsurface geologic data and operating and development costs. Our Vice President of Geology and our Vice President of Operations primarily responsible for overseeing the preparations of our reserve estimates. Our Vice President of Geology holds a Bachelor of Arts in Geophysical Science from The University of Chicago and a Master of Business Administration from the Else School of Management, Millsaps College and has over 38 years of geology, operations and management experience in the oil and gas industry, having held numerous executive positions for public and private companies. Our Vice President of Operations holds a

Bachelor of Science and Master of Science in Engineering from the University of Texas and has over 23 years of drilling and operational engineering expertise at large and private companies.

The preparation of our proved reserve estimates was completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of producing formations, well targets and the development plan by our Vice President of Geology and Vice President of Operations;
- review and verification of historical production data, which data is based on actual production as reported by us;
- review of well by well reserve estimates by independent reserve engineers;
- review by our Vice President of Geology and our Vice President of Operations of all of our reported proved reserves, including the review of all significant reserve changes and all new PUD additions;
- direct reporting responsibilities by our Vice President of Geology and our Vice President of Operations to our Chief Executive Officer; and
- verification of property ownership interests by our land department.

Under the rules promulgated by the SEC, 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, 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). If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2018, 2017 and 2016 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (i) production performance-based methods; (ii) material balance-based methods; (iii) volumetric-based methods; and (iv) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a reasonably high degree of accuracy. Non-producing reserve estimates for developed and undeveloped properties were forecasted using analogy methods. This method provides a reasonably high degree of accuracy for predicting proved developed non-producing and PUD locations for our properties, due to the abundance of analog data.

To estimate economically recoverable proved reserves and related future net cash flows with respect to the carve-out figures for the December 31, 2016 reserves, Ryder Scott and management considered many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data, which cannot be measured directly, economic criteria based on current costs, SEC pricing requirements and forecasts of future production rates. Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. 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 proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data, historical well costs and operating expense data.

Summary of oil, natural gas and NGL reserves

At December 31, 2018, our estimated proved oil and natural gas reserves were48,364 MBoe and determined in accordance with the rules and regulations of the SEC. Based on this report, at December 31, 2018, our proved reserves were approximately 69% oil, 15% natural gas, 16% NGLs and 56% proved developed. The calculated percentages include proved developed non-producing reserves. At December 31, 2018, all of our proved reserves were located in the Permian Basin.

The following table presents our estimated net proved oil, natural gas and natural gas liquids reserves as of the fiscal years indicated:

	December 31,		
	2018 (1)	**2017 (2)**	**2016 (3)**
Proved reserves:			
Oil (MBbls)	33,158	18,436	7,356
Natural gas (MMcf)	44,583	39,316	17,355
NGL (MBbls)	7,775	6,142	2,985
Total (MBoe)	48,364	31,131	13,234
Proved developed reserves:			
Oil (MBbls)	18,464	8,814	3,068
Natural gas (MMcf)	26,194	14,171	10,574
NGL (MBbls)	4,477	2,285	1,802
Total (MBoe)	27,307	13,461	6,632
Proved undeveloped reserves:			
Oil (MBbls)	14,694	9,622	4,288
Natural gas (MMcf)	18,388	25,145	6,781
NGL (MBbls)	3,298	3,857	1,183
Total (MBoe)	21,057	17,670	6,601
Oil (per Bbl)	$ 65.56	$ 51.34	$ 42.75
Natural gas (per Mcf)	$ 3.10	$ 2.98	$ 2.49
Natural gas liquids (per Bbl)	$ 23.02	$ 31.82	$ 11.73

(1) Estimated net proved reserves were determined using average first-day-of-the-month prices for the prior twelve months in accordance with SEC guidance. For oil, the average West Texas Intermediate posted price of $65.56 per barrel as of December 31, 2018 was adjusted for quality, transportation fees and a regional price differential. For natural gas volumes, the average Henry Hub spot price of $3.10 per MMBtu as of December 31, 2018 was adjusted for energy content and a regional price differential. For NGL volumes, NGL prices range from 34% to 46%, depending on the property, of the average West Texas Intermediate posted price of $65.56 per barrel. The average adjusted NGL price weighted by production was $23.02 per barrel as of December 31, 2018. All prices are held constant throughout the producing life of the properties.

(2) Estimated net proved reserves were determined using average first-day-of-the-month prices for the prior twelve months in accordance with SEC guidance. For oil, the average West Texas Intermediate posted price of $51.34 per barrel as of December 31, 2017 was adjusted for quality, transportation fees and a regional price differential. For natural gas volumes, the average Henry Hub spot price of $2.98 per MMBtu as of December 31, 2017 was adjusted for energy content and a regional price differential. For December 31, 2017, NGLs were priced at $31.82 per barrel using Mont Belvieu pricing, as adjusted, and not as a percentage of West Texas Intermediate. All prices are held constant throughout the producing life of the properties.

(3) Estimated net proved reserves were determined using average first-day-of-the-month prices for the prior twelve months in accordance with SEC guidance. For oil, the average West Texas Intermediate posted price of $42.75 per barrel as of December 31, 2016 was adjusted for quality, transportation fees and a regional price differential. For natural gas volumes, the average Henry Hub spot price of $2.49 per MMBtu as of December 31, 2016 was adjusted for energy content and a regional price differential. For NGL volumes, 27.5% of the average West Texas Intermediate posted price of $42.75 per barrel, or $11.73, as of December 31, 2016 was adjusted for quality, transportation fees and a regional price differential. All prices are held constant throughout the producing life of the properties.

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. 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 "Risk Factors."

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K and the reserve report as of December 31, 2018, which is included as an exhibit to this Annual Report on Form 10-K.

Our proved reserves increased by 17,233 MBoe from 31,131 MBoe at December 31, 2017 to 48,364 MBoe at December 31, 2018. The increase was due to extensions of 25,427 MBoe partially offset by production of 6,693 MBoe and negative revisions of 1,501 MBoe. The increase due to extensions is primarily the result of the increased drilling in the Wolfcamp and Bone Spring formations in the Northern Delaware Basin and the negative revision is primarily due to PUD demotions partially offset by improved economics used in the reserve report.

Proved undeveloped reserves (PUDs)

As of December 31, 2018, our proved undeveloped reserves totaled 14,694 MBbls of oil, 18,388 MMcf of natural gas and 3,298 MBbls of natural gas liquids, for a total of 21,057 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells are drilled and begin production.

The following table summarizes the changes in PUD reserves for the year ended December 31, 2018 in MBoe:

December 31, 2017	17,670
Extensions, discoveries and other additions	16,174
Performance and price revisions	(6,030)
Acquisition of reserves	—
Disposition of reserves	—
Transferred to proved developed reserves	(6,757)
December 31, 2018	21,057

As of December 31, 2018, we had 44 operated PUD locations booked of which, 3 locations were originally booked at December 31, 2015, 2 location was originally booked at December 31, 2016, 4 locations were originally booked at December 31, 2017 and 35 locations were booked at December 31, 2018. The negative PUD revisions were primarily due to 8 PUD locations being demoted in 2018 due to a change in development plan.

During 2018, we spent a total of $63.9 million related to the development of PUDs, which resulted in the conversion of 6,757 MMBoe of PUDs to proved developed reserves. Our development plan resulted in 10 PUDs drilled in 2018. As of December 31, 2018, we had 8 DUCs included in PUDs which we incurred approximately $27.2 million developing. Plans for 2019 include drilling 22 PUD targets. We believe that our progress in 2018 demonstrates our ability to execute on our development plan. Our development plan sets forth the remaining PUD locations to be brought to proved producing status within five years of initial booking. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast as well as access to liquidity sources.

Oil and Natural Gas Production Prices and Production Costs

The prices that we receive for the oil, natural gas and natural gas liquids we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil, natural gas and NGL prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil, natural gas and NGL reserves that may be economically produced and our ability to access capital markets. Please see "Risk Factors - Risks Related to Our Operations - Oil, natural gas and NGL prices are volatile. A reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments."

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

	Year Ended December 31,		
	2018	2017	2016
Production data:			
Oil (MBbls)	4,913	1,271	612
Natural gas (MMcf)	5,231	2,709	2,381
Natural gas liquids (MBbls)	908	408	358
Total production (MBoe)	6,693	2,131	1,367
Average daily production (Boe/d)	18,337	5,838	3,734
Average realized prices before effect of derivatives (1):			
Oil (per Bbl)	$ 55.27	$ 48.46	$ 40.52
Natural gas (per Mcf)	1.80	2.65	2.23
Natural gas liquids (per Bbl)	23.07	18.31	12.68
Average price (per Boe)	$ 45.10	$ 35.77	$ 25.35
Average price after the effect of settled derivatives (per Boe) (1)	$ 42.79	$ 35.85	$ 22.30
Average costs (per Boe)			
Lease operating expenses	$ 5.83	$ 5.11	$ 3.51
Production taxes	2.17	1.66	1.13
Gathering and transportation	0.74	1.40	1.75
Depreciation, depletion, amortization and accretion	21.19	16.94	18.27
Impairment of oil and natural gas properties	—	0.50	—
Exploration costs	0.65	0.82	0.58
General and administrative, excluding stock-based compensation	3.58	5.72	4.51
Stock-based compensation	0.97	0.58	—
Transaction costs	—	1.23	2.07
(Gain) loss on disposition of property and equipment	0.07	(2.34)	(0.04)
Total operating expenses per Boe	$ 35.20	$ 31.62	$ 31.78

(1)Average prices shown in the table reflect prices both before and after the effects of commodity hedging settlements. Our calculation of such effects includes both gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

Drilling activity and results

The following table summarizes our drilling activity for the last three years.

	Year Ended December 31,			Year Ended December 31,		
	2018	2017	2016	2018	2017	2016
	Gross			Net		
Exploratory Wells:						
Productive (1)	17	15	3	17	15	2
Dry	—	—	—	—	—	—
Development Wells:						
Productive (1)	13	4	2	13	4	2
Dry	—	—	—	—	—	—
Total Wells						
Productive (1)	30	19	5	30	19	4
Dry holes	—	—	—	—	—	—
	30	19	5	30	19	4

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells for which there is no production history.

Productive wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2018. This table does not include wells in which we own a royalty interest only.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Core Operating Areas:						
Northern Delaware Basin	58	13	71	54	13	67
Southern Delaware Basin	13	3	16	11	2	13
Total	71	16	87	65	15	80

As of December 31, 2018, we had an average working interest of 92.0% in our productive wells. Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest and net wells are the sum of our fractional working interests owned in gross wells.

Our acreage

The following table sets forth information as of December 31, 2018 relating to our Delaware Basin leasehold acreage.

	Developed Acres		Undeveloped Acres		Total Acres	
Core Acreage Area:	Gross	Net	Gross	Net	Gross	Net
Northern Delaware Basin	6,345	3,970	320	40	6,665	4,010
Southern Delaware Basin	3,504	2,915	5,715	4,658	9,219	7,573
Total	9,849	6,885	6,035	4,698	15,884	11,583

We are the operator of approximately 93.1% of our net acreage. In addition, we own mineral interests underlying approximately15,884 gross (11,583 net) of these acres, with an average royalty interest of 68.6% in our net acres. In 2018, we drilled25 gross (25 net) wells in our Northern Delaware Basin leasehold acreage and8 gross (8 net) wells in our Southern Delaware Basin leasehold acreage. As of December 31, 2018, we had 2 operated rigs running, 3 operated wells drilling and an inventory of8 operated wells awaiting completion. We expect to continue to concentrate drilling activities within our core acreage in 2019, primarily targeting the Bone Spring and Wolfcamp formations.

Undeveloped acreage expirations

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2018, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates. Subsequent to December 31, 2018, we established production to hold the acreage that was scheduled to expire in 2019.

	2019		2020		2021		2022		2023	
Expirations	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Delaware Basin	—	—	—	—	—	—	—	—	—	—
Southern Delaware Basin	640	640	5,565	3,246	1,276	420	320	320	—	—
Total	640	640	5,565	3,246	1,276	420	320	320	—	—

Title to properties

We believe that we have satisfactory title to our producing properties in accordance with generally accepted industry standards. As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties for an acquisition of leasehold acreage. We perform a thorough title examination and curative work with respect to significant defects either prior to an acquisition of producing properties or prior to commencement of drilling operations on those properties. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we have satisfactory title to all our material assets. Although title to these properties is in some cases subject to encumbrances, 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.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. We do not believe the results of any legal proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations or liquidity.

ITEM 4. MINE SAFETY DISCLOSURES

None.

PART II

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

Market Information

Our Class A Common Stock, Public Warrants and Units are currently quoted on NASDAQ under the symbols "ROSE," "ROSEW" and "ROSEU," respectively. Through April 26, 2017, our Class A Common Stock was quoted under the symbol "KLRE." There is no public market for our Class B Common Stock.

Holders of Record

Approximately 20 registered stockholders of record held our Class A Common Stock as of March 22, 2019. This number does not include owners or stockholders who beneficially own our shares through a broker or other entity who may hold shares in a "street name." On March 22, 2019, we had one holder of record of our Class B Common Stock.

Dividend Policy

We have not paid any cash dividends on our Class A Common Stock to date and do not currently contemplate paying dividends in the foreseeable future. The payment of cash dividends in the future will be dependent upon our revenues and earnings, if any, capital requirements and general financial condition. The payment of any future cash dividends will be within the discretion of our board of directors.

Pursuant to the Series A Certificate of Designation, holders of Series A Preferred Stock are entitled to receive, when, as and if declared by our board of directors, cumulative dividends, payable in cash, Series A Preferred Stock, or a combination thereof, in each case, at the sole discretion of the Company, at an annual rate of 8% on the $1,000 liquidation preference per share of the Series A Preferred Stock, payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year, beginning on July 15, 2017.

Pursuant to the Series B Certificate of Designation, holders of Series B Preferred Stock are entitled to receive, when, as and if declared by our board of directors, cumulative dividends, payable in cash, or with respect to dividends declared for any quarter ending on or prior to January 15, 2019, a combination of cash and Series B Preferred Stock, in each case, at the sole discretion of the Company, at an annual rate of 10% on the $1,000 liquidation preference per share of the Series B Preferred Stock, payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year, beginning on January 15, 2018.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
January 2018	—	$ —	n/a	n/a
February 2018	—	—	n/a	n/a
March 2018	—	—	n/a	n/a
April 2018	32,261	7.95	n/a	n/a
May 2018	—	—	n/a	n/a
June 2018	—	—	n/a	n/a
July 2018	—	—	n/a	n/a
August 2018	—	—	n/a	n/a
September 2018	—	—	n/a	n/a
October 2018	—	—	n/a	n/a
November 2018	61,460	7.98	n/a	n/a
December 2018	—	—	n/a	n/a
Total 2018	93,721	$ 7.97	n/a	n/a

(1) These shares were withheld upon the vesting of employee restricted stock grants in connection with payment of required withholding taxes.

Equity Compensation Plan Information

On April 27, 2017, our stockholders approved the Long-Term Incentive Plan. See more details and discussion of the plan in Note 14 - *Stock Based Compensation.*

Plan category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plan approved by security holders	1,322,850	$ —	5,757,254
Total	1,322,850	$ —	5,757,254

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data 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," both contained herein.

The following table shows our and Rosehill Operating's selected consolidated historical financial information for the periods indicated. The selected historical financial balance sheet data of Rosehill Operating as of December 31, 2016 and 2015 and the statement of operations and cash flow data for the years ended December 31, 2016, 2015 and 2014 was derived from the audited carve-out historical financial statements of Tema. We have no direct operations and no significant assets other than our ownership interest in Rosehill Operating, an entity of which we act as the sole managing member and of whose Rosehill Operating Common Units we currently own approximately 31.6% (or 43.1% assuming the conversion of our Rosehill Operating Series A Preferred Units into Rosehill Operating Common Units). Unless the context otherwise requires, (i) prior to the completion of the Transaction, references to "Rosehill Operating" refer to the assets, liabilities and operations of the business that were contributed to Rosehill Operating Company, LLC in connection with the Transaction and (ii) following the completion of the Transaction, references to "Rosehill Operating" refer to Rosehill Operating Company, LLC.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands, except per share data)				
STATEMENTS OF OPERATIONS DATA					
Total revenues	$ 301,875	$ 76,236	$ 34,645	$ 29,487	$ 43,563
Operating income (loss)	66,263	8,894	(8,803)	(15,207)	(16,504)
Net income (loss)	117,962	(11,948)	(15,189)	(14,820)	(19,253)
Series A Preferred Stock dividends and deemed dividends	7,938	12,936	—	—	—
Series B Preferred Stock dividends, deemed dividends and return	23,437	2,447	—	—	—
Net income (loss) attributable to Rosehill Resources Inc. common stockholders	26,661	(8,520)	(15,189)	(14,820)	(19,253)
Earnings (loss) per common share:					
Basic	$ 3.25	$ (1.43)	$ (2.59)	(2.53)	(3.29)
Diluted	$ 1.76	$ (1.43)	$ (2.59)	(2.53)	(3.29)
Weighted average common shares outstanding - basic	8,196	5,945	5,857	5,857	5,857
Weighted average common shares outstanding - diluted	46,499	5,945	5,857	5,857	5,857
Pro forma per share data(1):					
Pro forma net loss attributable to Rosehill Resources Inc. common stockholders		$ (8,068)	$ (12,355)		
Pro forma loss per share					
Basic and diluted		$ (1.36)	$ (2.11)		
Pro forma weighted average common shares outstanding					
Basic and diluted		5,945	5,857		
CASH FLOW DATA					
Net cash provided by (used in):					
Operating activities	$ 176,309	$ 37,759	$ 11,461	$ 18,244	$ 25,525
Investing activities	(399,343)	(265,497)	(22,164)	(16,993)	(53,392)
Financing activities	218,509	243,986	(8,597)	17,519	23,457
Other financial data:					
Adjusted EBITDAX (unaudited)(2)	$ 204,359	$ 46,766	$ 18,949	$ 21,743	$ 28,032

(1) The pro forma data is provided for illustrative purposes only. We incurred non-recurring transaction costs that were directly attributable to the Transaction of $2.6 million and $2.8 million for the years ended December 31, 2017 and 2016, respectively. Pro forma per share data was recalculated excluding transaction costs. The portion of transaction costs related to our ownership interest in Rosehill Operating was reduced from the net loss attributable to Rosehill Resources Inc. common stockholders.

(2) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of net income to Adjusted EBITDAX, see “Management's Discussion and Analysis of Financial Condition and Results of Operations - Non-GAAP Financial Measure”.

	December 31,			
	2018	**2017**	**2016**	**2015**
BALANCE SHEET DATA	(in thousands, except per share data)			
Total current assets	$ 84,685	$ 43,543	$ 16,343	33,696
Property and equipment, net	669,389	432,615	123,373	122,873
Total assets	817,066	476,982	139,826	156,903
Total current liabilities	79,164	103,400	14,223	29,165
Long term debt, net	288,298	93,199	55,000	45,000
Mezzanine equity - Series B Preferred Stock	155,111	140,868	—	—
Noncontrolling interest	113,770	12,054	—	—
Total stockholder’s equity / parent net investment	267,337	122,664	65,220	78,977

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the consolidated financial statements and notes thereto appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside of our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGLs, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are an independent oil and natural gas company focused on the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin. We have drilling locations in ten distinct formations in the Delaware Basin in: the Brushy Canyon, Upper Avalon, Lower Avalon, 2nd Bone Spring Shale, 2nd Bone Spring Sand, 3rd Bone Spring Sand, 3rd Bone Spring Shale, Wolfcamp A (X/Y), Lower Wolfcamp A and Wolfcamp B, and our goal is to build a premier development and acquisition company focused on horizontal drilling in the Delaware Basin.

We have no direct operations and no significant assets other than our ownership interest in Rosehill Operating, an entity of which we act as the sole managing member and of whose common units we currently own approximately 31.6% (or 43.1% assuming the conversion of Rosehill Operating Series A Preferred Units into Rosehill Operating common units).

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;
- operating expenses on a per Barrel of oil equivalent ("Boe");
- cost of reserve additions from drilling operations; and
- Adjusted EBITDAX as defined under "Non-GAAP Financial Measure."

Market Conditions

The oil and natural gas industry is cyclical and commodity prices are highly volatile. In the second half of 2014, oil prices began a rapid and significant decline as the global oil supply began to outpace demand. During 2015, 2016 and early 2017, the global oil supply continued to outpace demand, resulting in a sustained decline in realized prices for oil production. In general, this imbalance between supply and demand reflected the significant supply growth achieved in the United States as a result of shale drilling and oil production increases by certain other countries, including the efforts of Russia and Saudi Arabia to retain market share, combined with only modest demand growth in the United States and less-than-expected demand in other parts of the world, particularly in Europe and China. NGL prices generally correlate to the price of oil. Prices for domestic natural gas began to decline during the third quarter of 2014 and continued to be weak during 2015 through 2017. This decline was primarily due to an imbalance between supply and demand across North America. Throughout 2018, commodity prices improved, yet remained volatile, and it is likely that commodity prices will continue to fluctuate due to global supply and demand, inventory supply levels, weather conditions, geopolitical and other factors. Due to these and other factors, commodity prices cannot be accurately predicted.

Realized Prices

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production, as well as NGLs that are extracted from our natural gas during processing. The following table presents our average realized commodity prices before the effects of commodity derivative settlements:

	Year Ended December 31,		
	2018	**2017**	**2016**
Crude Oil (per Bbl)	$ 55.27	$ 48.46	$ 40.52
Natural Gas (per Mcf)	$ 1.80	$ 2.65	$ 2.23
NGLs (per Bbl)	$ 23.07	$ 18.31	$ 12.68

Lower commodity prices in the future could result in impairments of our properties and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity, or ability to finance planned capital expenditures. Lower oil, natural gas and NGL prices may also reduce the borrowing base under our Amended and Restated Credit Agreement, which may be determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil, natural gas and NGL prices may result in significant non-cash fair value losses being incurred on our commodity derivatives, which could cause us to experience net losses when oil and natural gas prices rise.

A 10% change in our realized oil, natural gas and NGL prices would have changed revenue by the following amounts for the periods indicated:

	Year Ended December 31,		
	2018	**2017**	**2016**
		(In thousands)	
Oil sales	$ 27,154	$ 6,160	$ 2,481
Natural gas sales	939	717	530
NGL sales	2,094	747	453
Total revenues	$ 30,187	$ 7,624	$ 3,464

The prices we receive for our products are based on benchmark prices and are adjusted for quality, energy content, transportation fees and regional price differentials. See “Results of Operations” below for an analysis of the impact changes in realized prices had on our revenues.

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. The following table shows the components of our revenues for the periods indicated, as well as the percentage each component contributed to total revenue.

	Year Ended December 31,		
Commodity Revenues (1):	**2018**	**2017**	**2016**
Oil sales	90%	81%	72%
Natural gas sales	3	9	15
NGL sales	7	10	13
	100%	100%	100%

(1) The percentages exclude the effects of commodity derivatives.

Approximately 60%, 80%, and 70% of total revenues for the years ended December 31, 2018, 2017, and 2016, respectively, were from Gateway, a related-party.

Operational and Financial Highlights for the years ended December 31, 2018, 2017 and 2016

Production Results

The following table presents production volumes for our properties for the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
Oil (MBbls)	4,913	1,271	612
Natural gas (MMcf)	5,231	2,709	2,381
NGL (MBbls)	908	408	358
Total (MBoe)	6,693	2,131	1,367
Average daily net production (Boe/d)	18,337	5,838	3,734

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through drilling as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to borrow or raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions.

Derivative Activity

To achieve a more predictable cash flow and reduce exposure to adverse fluctuations in commodity prices, we have historically used commodity derivative instruments, such as swaps, two-way costless collars and three-way costless collars, to hedge price risk associated with a portion of our anticipated oil and natural gas production. By removing a significant portion of the price volatility associated with our oil and natural gas production, we will mitigate, but not eliminate, the potential negative effects of declines in benchmark oil and natural gas prices on our cash flow from operations for those periods. However, in a portion of our current positions, hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our commodity derivative contract prices are lower than market prices and, conversely, we will sustain gains to the extent our commodity derivative contract prices are higher than market prices. In certain circumstances, where we have unrealized gains in our commodity derivatives portfolio, we may choose to restructure existing commodity derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions.

A description of our derivative financial instruments is provided below:

- A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract value.

- A two-way costless collar is an arrangement that contains a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party and (3) if the index price is below the floor price, we will receive the difference between the floor price and the index price.

- A three-way costless collar is an arrangement that contains a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the sold call strike price, we pay the counterparty the difference between the index price and sold call strike price, (2) if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party, (3) if the index price is between the sold put strike price and the purchased put strike price, we will receive the difference between the purchased put strike price and the index price and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price.

- A purchased put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless.

- A sold call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

We had a net current asset of $30.8 million and a net long-term asset of $58.3 million related to the following open commodity derivative instrument positions as of December 31, 2018:

	2019	2020	2021	2022
Commodity derivative swaps				
Oil:				
Notional volume (Bbls)	2,664,000	1,960,000	2,160,000	1,100,000
Weighted average fixed price ($/Bbl)	$ 53.59	$ 60.09	$ 61.21	$ 58.42
Natural gas:				
Notional volume (MMBtu)	2,220,000	1,500,000	1,200,000	1,200,000
Weighted average fixed price ($/MMbtu)	$ 2.88	$ 2.84	$ 2.85	$ 2.87
Ethane:				
Notional volume (Gallons)	12,444,138	—	—	—
Weighted average fixed price ($/Gallons)	$ 0.28	$ —	$ —	$ —
Propane:				
Notional volume (Gallons)	8,296,218	—	—	—
Weighted average fixed price ($/Gallons)	$ 0.79	$ —	$ —	$ —
Pentanes:				
Notional volume (Gallons)	2,765,700	—	—	—
Weighted average fixed price ($/Gallons)	$ 1.47	$ —	$ —	$ —
Commodity derivative two-way collars				
Oil:				
Notional volume (Bbls)	601,000	—	—	—
Weighted average ceiling price ($/Bbl)	$ 61.30	$ —	$ —	$ —
Weighted average floor price ($/Bbl)	$ 55.21	$ —	$ —	$ —
Commodity derivative three-way collars				
Oil:				
Notional volume (Bbls)	1,531,832	3,294,000	—	—
Weighted average ceiling price ($/Bbl)	$ 68.52	$ 70.29	$ —	$ —
Weighted average floor price ($/Bbl)	$ 57.62	$ 57.50	$ —	$ —
Weighted average sold put option price ($/Bbl)	$ 45.51	$ 47.50	$ —	$ —
Crude oil basis swaps				
Midland / Cushing:				
Notional volume (Bbls)	4,800,832	3,513,600	—	—
Weighted average fixed price ($/Bbl)	$ (4.93)	$ (1.43)	$ —	$ —
Natural gas basis swaps				
EP Permian:				
Notional volume (MMBtu)	1,781,472	2,096,160	—	—
Weighted average fixed price ($/MMBtu)	$ (1.03)	$ (1.03)	$ —	$ —

If there are no changes in the forward curve market prices as of December 31, 2018, we would incur a realized gain of $30.8 million, $29.1 million, $22.0 million and $7.2 million for 2019, 2020, 2021 and 2022, respectively. See Note 5 - *Derivative Instruments* in the consolidated financial statements under Part II, Item 8 of this Annual Report on Form 10-K for additional information about our derivatives.

Principal Components of Our Cost Structure

Operating Costs and Expenses

Costs associated with producing oil, natural gas and NGLs are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production, and others are a function of the number of wells we own.

Lease Operating Expenses. Lease operating expenses ("LOE") are the costs incurred in the operation of producing properties and workover costs. Expenses for direct labor, water/gas injection, water handling and disposal, compressor rental and chemicals comprise the most significant portion of our LOE. Certain items, such as direct labor and compressor rental, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For example, repairs to our pumping equipment or surface facilities result in increased LOE in periods during which they are performed. Certain of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and / or water increases or decreases. For example, we incur water disposal costs in connection with various production-related activities, such as trucking water for disposal until connection can be made to a water disposal well. We are also subject to ad valorem taxes, which is included in LOE, in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties.

Although we strive to reduce our LOE, these expenses can increase or decrease on a per unit basis as a result of various factors as we operate our properties or make acquisitions and dispositions of properties. For example, we may increase field level expenditures to optimize our operations, incurring higher expenses in one quarter relative to another, or we may acquire or dispose of properties that have different LOE per Boe. These initiatives would influence our overall operating costs and could cause fluctuations when comparing LOE on a period to period basis.

Production Taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold at fixed rates established by federal, state, or local taxing authorities. In general, the production taxes we pay correlate to the changes in oil, natural gas and NGL revenues.

Gathering and Transportation Expense. Gathering and transportation expense principally consists of expenditures to prepare and transport production from the wellhead to a specified sales point and gas processing costs. These costs will fluctuate with increases or decreases in production volumes, contractual fees and changes in fuel and compression costs.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization ("DD&A") is the systematic expensing of the capitalized costs incurred to acquire and develop oil and natural gas properties. We use the successful efforts method of accounting for oil and natural gas activities, and, as such, we capitalize all costs associated with our development and acquisition efforts and all successful exploration efforts, which are then depleted using the unit of production method. Deprecation of the cost of other property, plant and equipment is generally calculated using the straight-line depreciation method over the useful lives of the assets.

Accretion Expense. Accretion expense is the periodic accreting of the present value of the estimated asset retirement liability to reflect the passage of time.

Impairment Expense. We review our proved properties and unproved leasehold costs for impairment whenever events and changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Impairment is reviewed and recorded on a property-by-property basis.

Exploration Costs. Exploration costs include exploratory seismic expenditures, other geological and geophysical costs, lease rentals and drilling costs of exploratory wells that are determined to be unsuccessful.

General and Administrative Expense. General and administrative ("G&A") expense reflects costs incurred for overhead, including both cash and stock-based compensation for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, audit and other fees for professional services and legal compliance. A portion of these expenses prior to the Transaction have been allocated to us from Tema (on the basis of direct usage when identifiable with the remainder allocated proportionately on a Boe basis).

Transaction Expense. Transaction expense reflects costs incurred in connection with the Transaction. Under the terms of the Business Combination Agreement dated December 31, 2016 (the "Business Combination Agreement"), Tema and Rosemore were entitled to be reimbursed for transaction expenses incurred through the closing of the transaction.

Interest Expense, Net. Interest paid to lenders under the Amended and Restated Credit Agreement and other borrowings and interest income earned on cash balances, is reflected in interest expense, net.

Income Taxes. Rosehill Operating is a limited liability company that is treated as a partnership for U.S. federal income tax purposes and is not subject to U.S. federal income tax. Rosehill Resources is a "C" corporation and is subject to U.S. federal, state and local income taxes. Any taxable income or loss generated by Rosehill Operating is passed through and included in Rosehill Resources and the noncontrolling interest taxable income or loss. On a consolidated basis, our effective tax rate will differ from the enacted statutory rate of 21% and will fluctuate from period to period primarily due to the allocation of profits and losses to Rosehill Resources and the noncontrolling interest holder in accordance with the LLC Agreement and the impact of state income taxes.

Non-GAAP Financial Measure

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by our management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) before interest expense, net, income tax expense (benefit), DD&A, accretion, impairment of oil and natural gas properties, exploration costs, stock-settled stock-based compensation, (gains) losses on commodity derivatives excluding net cash receipts (payments) on settled commodity derivatives, one-time costs incurred in connection with the Transaction, gains and losses from the sale of property and equipment, (gains) losses on asset retirement obligation settlements and other non-cash operating items. Adjusted EBITDAX is not a measure of net income (loss) as determined by United States generally accepted accounting principles ("U.S. GAAP").

Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate operating performance and compare our results of operations from period to period and against our peers without regard to financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures, and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with U.S. GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that its results will be unaffected by unusual or non-recurring items. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies.

We have provided below a reconciliation of Adjusted EBITDAX to net loss, the most directly comparable U.S. GAAP financial measure.

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Net income (loss)	$ 117,962	$ (11,948)	$ (15,189)
Interest expense, net	19,489	2,532	1,822
Income tax expense	18,162	1,690	148
Depreciation, depletion, amortization and accretion	141,815	36,091	24,965
Impairment of oil and natural gas properties	—	1,061	—
Unrealized (gain) loss on commodity derivatives, net	(108,086)	16,553	3,345
Transaction costs	—	2,618	2,834
Stock settled stock-based compensation	6,477	1,245	—
Exploration costs	4,374	1,747	794
(Gain) loss on disposition of property and equipment	499	(4,995)	(50)
Other non-cash expense, net	3,667	172	280
Adjusted EBITDAX	$ 204,359	$ 46,766	$ 18,949

Factors Affecting the Comparability of Our Future Financial Data Results to the Historical Financial Results of Rosehill Operating

Our future results of our operations may not be comparable to the historical results of operations of Rosehill Operating for the periods presented due to the following reasons:

Income Taxes. Rosehill Operating is a limited liability company that is treated as a partnership for U.S. federal income tax purposes and for purposes of certain state and local income taxes. Rosehill Operating is not subject to U.S. federal income taxes. However, Rosehill Operating is subject to the Texas margin tax at a rate of 0.75%. Any taxable income or loss generated by Rosehill Operating is passed through to and included in the taxable income or loss of its members, including us, on a pro rata basis. We are a corporation and are subject to U.S. federal income taxes, in addition to state and local income taxes with respect to its allocable share of any taxable income or loss of Rosehill Operating, as well as any stand-alone income or loss generated by us.

In connection with the closing of the Transaction, we entered into a Tax Receivable Agreement with Tema. This agreement generally provides for the payment by us to Tema of 90% of the net cash savings, if any, in U.S. federal, state and local income tax and franchise tax that we actually realize (computed using simplifying assumptions to address the impact of state and local taxes) or are deemed to realize in certain circumstances in periods after the Transaction as a result of certain increases in the tax basis in the assets of Rosehill Operating and certain benefits attributable to imputed interest. We will retain the benefit of the remaining 10% of these cash savings.

Payments will generally be made under the Tax Receivable Agreement as we realize actual cash tax savings in periods after the Transaction from the tax benefits covered by the Tax Receivable Agreement. However, if the Tax Receivable Agreement terminates early, either at our election in connection with certain mergers or other changes of control or as a result of our breach of a material obligation thereunder, we could be required to make a substantial, immediate lump sum payment in advance of any actual cash tax savings. We will be dependent on Rosehill Operating to make distributions to us in an amount sufficient to cover our obligations under the Tax Receivable Agreement.

Public Company Expenses. We incur direct G&A expense as a result of being a publicly traded company, including, but not limited to, costs associated with hiring new personnel, implementation of compensation programs that are competitive with our public company peer group, annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. These direct G&A expenses are not included in Rosehill Operating's historical financial results of operations prior to the Transaction date of April 27, 2017.

Results of Operations

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

Oil, Natural Gas and NGL Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average sales prices and volumes:

	Year Ended December 31, 2018	Year Ended December 31, 2017	Change	Change %
	(Dollars in thousands, except price data)			
Revenues:				
Oil sales	$ 271,539	$ 61,596	$ 209,943	341 %
Natural gas sales	9,392	7,171	2,221	31
NGL sales	20,944	7,469	13,475	180
Total revenues	$ 301,875	$ 76,236	$ 225,639	296 %
Average sales price (1):				
Oil (per Bbl)	$ 55.27	$ 48.46	$ 6.81	14 %
Natural gas (per Mcf)	1.80	2.65	(0.85)	(32)
NGLs (per Bbl)	23.07	18.31	4.76	26
Total (per Boe)	$ 45.10	$ 35.77	$ 9.33	26 %
Total, including effects of gain (loss) on settled commodity derivatives, net (per Boe)	$ 42.79	$ 35.85	$ 6.94	19 %
Net production:				
Oil (MBbls)	4,913	1,271	3,642	287 %
Natural gas (MMcf)	5,231	2,709	2,522	93
NGLs (MBbls)	908	408	500	123
Total (MBoe)	6,693	2,131	4,562	214 %
Average daily net production volume:				
Oil (Bbls/d)	13,460	3,483	9,977	286 %
Natural gas (Mcf/d)	14,332	7,423	6,909	93
NGLs (Bbls/d)	2,488	1,118	1,370	123
Total (Boe/d)	18,337	5,838	12,499	214 %

(1) Excluding the effects of settled and unsettled commodity derivative transactions unless noted otherwise.

The increase in total revenues was due to higher sales volumes and higher average sales prices. The increase in average sales price contributed approximately $33.3 million of the increase in total revenues and the increase in sales volume contributed approximately $192.3 million of the increase in total revenues. The increase in sales volume is primarily attributable to additional wells going into production in 2017 and 2018. In 2019 and forward, we do not expect the adoption of ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASC 606"), to have an impact on our net income; however, we expect certain changes to the presentation between oil, natural gas, and NGL revenues and gathering and transportation expenses based on where control of our oil, natural gas, and NGLs production transfers to the customer. The expected change will impact the reported average sales price for each product.

Operating Expenses. The following table summarizes our operating expenses for the periods indicated:

	Year Ended December 31,			
	2018	2017	Change	Change %
	(In thousands, except per Boe data)			
Operating expenses:				
Lease operating expenses	$ 39,010	$ 10,881	$ 28,129	259 %
Production taxes	14,506	3,535	10,971	310
Gathering and transportation	4,939	2,976	1,963	66
Depreciation, depletion, amortization and accretion	141,815	36,091	105,724	293
Impairment of oil and natural gas properties	—	1,061	(1,061)	(100)
Exploration costs	4,374	1,747	2,627	150
General and administrative, excluding stock-based compensation	23,947	12,183	11,764	97
Stock-based compensation	6,522	1,245	5,277	424
Transaction costs	—	2,618	(2,618)	(100)
(Gain) loss on disposition of property and equipment	499	(4,995)	5,494	(110)
Total operating expenses	$ 235,612	$ 67,342	$ 168,270	250 %
Operating expenses per Boe:				
Lease operating expenses	$ 5.83	$ 5.11	$ 0.72	14 %
Production taxes	2.17	1.66	0.51	31
Gathering and transportation	0.74	1.40	(0.66)	(47)
Depreciation, depletion, amortization and accretion	21.19	16.94	4.25	25
Impairment of oil and natural gas properties	—	0.50	(0.50)	(100)
Exploration costs	0.65	0.82	(0.17)	(21)
General and administrative, excluding stock-based compensation	3.58	5.72	(2.14)	(37)
Stock-based compensation	0.97	0.58	0.39	67
Transaction costs	—	1.23	(1.23)	(100)
(Gain) loss on disposition of property and equipment	0.07	(2.34)	2.41	(103)
Total operating expenses per Boe	$ 35.20	$ 31.62	$ 3.58	11 %

Lease operating expenses. The increase in LOE was due to higher sales volumes and a higher average LOE rate. The increase in sales volume contributed approximately $23.3 million of the increase in LOE, and the increase in the LOE rate contributed approximately $4.8 million of the increase in LOE. The higher sales volume is primarily attributable to additional wells going into production throughout 2017 and 2018. The higher LOE rate is primarily due to increases in water disposal costs and equipment rentals.

Production taxes. Production taxes are primarily based on the market value of our wellhead production. The increase was primarily due to increased total revenues. Our total revenues increased by 296% and production taxes increased by 310%. Production taxes as a percentage of total revenues were approximately 4.8% and 4.6% for the year ended December 31, 2018 and 2017, respectively.

Gathering and transportation. Gathering and transportation expenses are primarily incurred with natural gas and NGL production. Gathering and transportation expenses increased by approximately $3.2 million due to an increase in sales volume of natural gas and NGLs partially offset by a decrease of approximately $1.2 million due to a decrease in gathering and transportation expense per Boe of natural gas and NGLs. The gathering and transportation expense per Boe decreased due to the disposition of our Barnett Shale assets in the fourth quarter of 2017, which had higher gathering and transportation expenses per Boe. In 2019 and thereafter, we do not expect the adoption of ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASC 606"), to have an impact on our net income; however, we expect certain changes to the presentation between oil, natural gas and NGL revenues and gathering and transportation expenses based on where control of our oil, natural gas and NGLs production transfers to the customer. The expected change will impact the reported gathering and transportation expense per Boe.

Depreciation, Depletion, Amortization and Accretion Expense ("DD&A"). See the following table for a breakdown of DD&A:

	Year Ended December 31,			
	2018	2017	Change	Change %
	(In thousands, except per Boe data)			
Components of DD&A				
Depreciation, depletion and amortization of oil and gas properties	$ 140,447	$ 35,414	$ 105,033	297 %
Depreciation of other property and equipment	730	360	370	103
Accretion expense	638	317	321	101
	$ 141,815	$ 36,091	$ 105,724	293 %
DD&A per Boe				
Depreciation, depletion and amortization of oil and gas properties	$ 20.98	$ 16.62	$ 4.36	26 %
Depreciation of other property and equipment	0.11	0.17	(0.06)	(35)
Accretion expense	0.10	0.15	(0.05)	(33)
Total DD&A per Boe	$ 21.19	$ 16.94	$ 4.25	25 %

DD&A for oil and gas properties increased by approximately $105.0 million due to an increase of approximately $75.8 million related to an increase in production and an increase of approximately $29.2 million due to an increase in the DD&A rate.

Impairment of oil and natural gas properties. Impairment for 2017 primarily relates to the write-down of our remaining proved property located in the Barnett Shale that was not included in the disposition of the Barnett Shale asset sale.

Exploration costs. Exploration costs include exploratory seismic expenditures, other geological and geophysical costs, lease rentals and drilling costs of exploratory wells that are determined to be unsuccessful. The increase for the year ended December 31, 2018 compared to the same period in 2017 was primarily due to ongoing seismic studies of the acreage we acquired in the White Wolf Acquisition.

General and Administrative, excluding stock-based compensation. The increase to G&A expense was primarily due to an increase in payroll and payroll related costs of approximately $7.6 million as a result of an increase in full-time employees. Also, there was an increase of approximately $1.5 million for public company expenses, including board of director fees and expenses, investor relations costs, filing fees, audit fees, and legal fees. In addition, we were reimbursed G&A expense of approximately $0.8 million from Tema under the Transition Service Agreement in 2017 and we did not receive such reimbursement in 2018. Furthermore, we incurred an increase of approximately $0.7 million in fees for consultants to assist with various corporate functions such as accounting and human resources. These expenses were not incurred at the same levels, or at all, in periods prior to the Transaction. The remaining increase primarily relates to an increase in general corporate costs such as insurance, office leases and employee costs.

Stock-based compensation. In April 2017, the stockholders approved the Long-Term Incentive Plan and grants were made beginning in July 2017. The increase to stock-based compensation was attributable to a greater amount of stock-based compensation outstanding during the year ended December 31, 2018 compared to the same period in 2017.

Transaction costs. We incurred transaction expenses of $2.6 million during the year ended December 31, 2017 related to the Transaction. We did not incur such costs in 2018 and do not expect to incur such costs from our normal operations going forward.

(Gain) loss on disposition of property and equipment. The loss on disposition of property and equipment for the year ended December 31, 2018 primarily relates to the write-off of other property and equipment and losses on asset retirement obligation settlements.

Other Income and Expenses. The following table summarizes our other income and expenses for the periods indicated:

	Year Ended December 31, 2018	Year Ended December 31, 2017	Change	Change %
	(In thousands)			
Other (expense) income:				
Interest expense, net	$ (19,489)	$ (2,532)	$ (16,957)	670 %
Gain (loss) on commodity derivative instruments, net	92,604	(16,336)	108,940	(667)
Other expense, net	(3,254)	(284)	(2,970)	1,046
Total other income (expense), net	$ 69,861	$ (19,152)	$ 89,013	(465)%

Interest Expense. The increase was primarily due to interest incurred of $10.0 million on the issuance of $100 million aggregate principal amount of 10.00% Senior Secured Second Lien Notes (the "Second Lien Notes") on December 8, 2017. There was also an increase of $5.9 million in interest expense related to our credit facility primarily as a result of an increase in borrowings outstanding. Furthermore, there was an increase of $1.4 million in amortization of debt discount and issuance costs primarily related to the Second Lien Notes deferred costs amortization and the write-off of the unamortized debt issuance costs associated with our old credit facility when we secured a new credit facility in March 2018.

Gain (loss) on commodity derivatives, net. Net gains and losses on our commodity derivatives are a function of fluctuations in the underlying commodity prices versus fixed hedge prices, time decay associated with options and the monthly settlement of the instruments. The total net gain for the year ended December 31, 2018 is comprised of net losses of $15.5 million on cash settlements and net gains of $108.1 million on mark-to-market adjustments on unsettled positions. The total net loss for the year ended December 31, 2017 is comprised of net gains of $0.2 million on cash settlements and net losses of $16.6 million on marked-to-market adjustments on unsettled positions.

Other income (expense), net. In connection with the Transaction, we entered into a Tax Receivable Agreement with the noncontrolling interest holder, Tema. The increase was primarily due to us recognizing a Tax Receivable Agreement liability of $3.5 million resulting from the distribution of the Cash Consideration to Tema in connection with the Transaction after concluding that it was probable that we would have sufficient future taxable income to utilize the related tax benefits.

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

Oil, Natural Gas and NGL Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average sales prices and volumes:

	Year Ended December 31,					
	2017		2016		Change	Change %
	(Dollars in thousands, except price data)					
Revenues:						
Oil sales	$	61,596	$	24,807	36,789	148%
Natural gas sales		7,171		5,304	1,867	35
NGL sales		7,469		4,534	2,935	65
Total revenues		76,236		34,645	41,591	120%
Average sales price (1):						
Oil (per Bbl)		48.46		40.52	7.94	20%
Natural gas (per Mcf)		2.65		2.23	0.42	19
NGLs (per Bbl)		18.31		12.68	5.63	44
Total (per Boe)		35.77		25.35	10.42	41%
Total, including effects of gain (loss) on settled commodity derivatives, net (per Boe)		35.85		22.30	13.55	61%
Net production:						
Oil (MBbls)		1,271		612	659	108%
Natural gas (MMcf)		2,709		2,381	328	14
NGLs (MBbls)		408		358	50	14
Total (MBoe)		2,131		1,367	764	56%
Average daily net production volume:						
Oil (Bbls/d)		3,483		1,673	1,810	108%
Natural gas (Mcf/d)		7,423		6,506	917	14
NGLs (Bbls/d)		1,118		977	141	14
Total (Boe/d)		5,838		3,734	2,104	56%

(1) Excluding the effects of settled and unsettled commodity derivative transactions unless noted otherwise.

The increase in total revenues was due to higher sales volumes and higher average sales prices. The increase in average sales price contributed approximately $13.5 million of the increase in total revenues and the increase in sales volume contributed approximately $28.1 million of the increase in total revenues. The increase in sales volume is primarily attributable to additional wells going into production in 2017.

Operating Expenses. The following table summarizes our operating expenses for the periods indicated:

	Year Ended December 31, 2017	Year Ended December 31, 2016	Change	Change %
	(In thousands, except per Boe data)			
Operating expenses:				
Lease operating expenses	$ 10,881	$ 4,800	$ 6,081	127 %
Production taxes	3,535	1,541	1,994	129
Gathering and transportation	2,976	2,398	578	24
Depreciation, depletion, amortization and accretion	36,091	24,965	11,126	45
Impairment of oil and natural gas properties	1,061	—	1,061	100
Exploration costs	1,747	794	953	120
General and administrative, excluding stock-based compensation	12,183	6,166	6,017	98
Stock-based compensation	1,245	—	1,245	100
Transaction costs	2,618	2,834	(216)	(8)
(Gain) loss on disposition of property and equipment	(4,995)	(50)	(4,945)	9,890
Total operating expenses	$ 67,342	$ 43,448	$ 23,894	55 %
Operating expenses per Boe:				
Lease operating expenses	$ 5.11	$ 3.51	$ 1.60	46 %
Production taxes	1.66	1.13	0.53	47
Gathering and transportation	1.40	1.75	(0.35)	(20)
Depreciation, depletion, amortization and accretion	16.94	18.27	(1.33)	(7)
Impairment of oil and natural gas properties	0.50	—	0.50	100
Exploration costs	0.82	0.58	0.24	41
General and administrative, excluding stock-based compensation	5.72	4.51	1.21	27
Stock-based compensation	0.58	—	0.58	100
Transaction costs	1.23	2.07	(0.84)	(41)
(Gain) loss on disposition of property and equipment	(2.34)	(0.04)	(2.30)	5,750
Total operating expenses per Boe	$ 31.62	$ 31.78	$ (0.16)	(1)%

Lease operating expenses. The increase in LOE was due to higher sales volumes and higher average LOE rate. The increase in average LOE per Boe contributed approximately $3.4 million of the increase in LOE and the increase in sales volume contributed approximately $2.7 million of the increase in LOE. The higher sales volume is primarily attributable to additional wells going into production throughout 2017. The higher LOE rate is primarily due to increases in water disposal costs, equipment rentals and ad valorem taxes.

Production taxes. Production taxes are primarily based on the market value of our wellhead production. The increase was primarily due to increased total revenues. Our total revenues increased by 120% and production taxes increased by 129%. Production taxes as a percentage of total revenues were approximately 4.6% and 4.4% for the year ended December 31, 2017 and 2016, respectively.

Gathering and transportation. Gathering and transportation expenses are primarily incurred with natural gas and NGL production. Gathering and transportation expenses increased by approximately $0.3 million due to an increase in sales volume of natural gas and NGLs and by an increase of approximately $0.2 million due to an increase in gathering and transportation expense per Boe of natural gas and NGLs.

Depreciation, Depletion, Amortization and Accretion Expense. See the following table for a breakdown of DD&A:

	Year Ended December 31,						
	2017		2016		Change		Change %
Components of DD&A	(In thousands, except per Boe data)						
Depreciation, depletion and amortization of oil and gas properties	$	35,414	$	24,432	$	10,982	45 %
Depreciation of other property and equipment		360		357		3	1
Accretion expense		317		176		141	80
	$	36,091	$	24,965	$	11,126	45 %
DD&A per Boe							
Depreciation, depletion and amortization of oil and gas properties	$	16.62	$	17.87	$	(1.25)	(7)%
Depreciation of other property and equipment		0.17		0.25		(0.08)	(32)
Accretion expense		0.15		0.12		0.03	25
Total DD&A per Boe	$	16.94	$	18.24	$	(1.30)	(7)%

DD&A for oil and gas properties increased by approximately $11.0 million due to an increase of approximately $13.7 million related to an increase in production and a decrease of approximately $2.7 million due to a decrease in DD&A rate. The reduction in the DD&A rate was primarily due to additions to proved reserves and proved developed reserves over the past twelve months at a higher rate than additions to drilling and completion costs being capitalized over that time period.

Impairment of oil and natural gas properties. Impairment for 2017 primarily relates to the write-down of our remaining proved property located in the Barnett Shale that was not included in the disposition of the Barnett Shale asset sale.

Exploration costs. Exploration costs include exploratory seismic expenditures, other geological and geophysical costs, lease rentals and drilling costs of exploratory wells that are determined to be unsuccessful. The increase for the year ended December 31, 2017 compared to the same period in 2016 was primarily due to increased geology and geophysics studies in the Permian Basin along with increased land title work. Our exploration costs did not contain any dry hole costs for the year ended December 31, 2017.

General and Administrative, excluding stock-based compensation. The increase to G&A expense was primarily due to an increase in payroll and payroll related costs of approximately $3.3 million. There was also an increase of approximately $1.3 million for public company expenses such as board of director fees and expenses, investor relations costs, filing fees, audit fees and legal fees. Furthermore, the company incurred an increase of approximately $1.2 million for consultants to assist with various corporate functions such as accounting and human resources. These expenses were not incurred at the same levels, or at all, in periods prior to the Transaction.

Stock-based compensation. Stock-based compensation increased during the year ended December 31, 2017 compared to the same period in 2016. In April 2017, the stockholders approved the Rosehill Resources Inc. Long-Term Incentive Plan and grants were made in 2017. There was no stock based compensation plan in 2016.

Transaction costs. Transaction costs incurred for the years ended December 31, 2017 and 2016 are related to the Transaction. We do not expect to incur such transaction costs from our normal operations going forward.

(Gain) loss on disposition of property and equipment. Gain on sale of property and equipment primarily relates to the disposition of the Barnett Shale assets. On November 2, 2017, we consummated the sale of our Barnett Shale assets for a purchase price of approximately $7.1 million. After customary purchase price adjustments, the net purchase price was approximately $6.5 million. The net book value of the Barnett Shales assets on the date of divestiture was $1.2 million, which resulted in a gain on sale of $5.3 million. The increase was partially offset by $0.3 million in losses upon asset retirement obligation settlements.

Other Income and Expenses. The following table summarizes our other income and expenses for the periods indicated:

	Year Ended December 31,			
	2017	2016	Change	Change %
	(In thousands)			
Other (expense) income:				
Interest expense, net	$ (2,532)	$ (1,822)	$ (710)	39%
Gain (loss) on commodity derivative instruments, net	(16,336)	(4,169)	(12,167)	292%
Other expense, net	(284)	(247)	(37)	15%
Total other income (expense), net	$ (19,152)	$ (6,238)	$ (12,914)	207%

Interest expense, net. The increase was primarily due to interest incurred on the issuance of $100 million aggregate principal amount of 10.00% Senior Secured Second Lien Notes issued on December 8, 2017.

Gain (loss) on commodity derivative instruments, net. Net gains and losses on our commodity derivatives are a function of fluctuations in the underlying commodity prices versus fixed hedge prices, time decay associated with options and the monthly settlement of the instruments. The total net loss for the year ended December 31, 2017 is comprised of net gains of $0.2 million on cash settlements and net losses of $16.6 million on mark-to-market adjustments on unsettled positions. The total net loss for the year ended December 31, 2016 is comprised of net losses of $0.8 million on cash settlements and net losses of $3.3 million on marked-to-market adjustments on unsettled positions.

Capital Requirements and Sources of Liquidity

Overview

Our development and acquisition activities require us to make significant operating and capital expenditures. Historically our primary sources of liquidity have been cash flows from operations, financing entered into in connection with the Transaction and the White Wolf Acquisition, proceeds from the sale of assets in the Barnett Shale, proceeds from our public offering of Class A Common Stock and borrowings under our credit facility. Our primary uses of cash have been for the acquisition and development of oil and natural gas properties, payments of operating and general and administrative costs and interest payments on outstanding debt.

We expect to continue funding our short-term and long-term growth with cash on hand, cash flow from operations, availability under our credit facility and/or opportunistically accessing the capital markets. The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of acquisition opportunities, our cash flows from operations, investing and financing activities, growth of our borrowing base and our ability to assimilate acquisitions and execute our drilling program. We review our capital expenditure forecast periodically to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements and other factors. We believe that our sources of funding will be sufficient to satisfy our currently anticipated cash requirements, including capital expenditures, working capital requirements and other liquidity requirements, through at least the next 12 months. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to execute on our drilling program. Further, our Amended and Restated Credit Agreement contains a financial covenant requiring us to maintain a current ratio of 1.0 to 1.0 at the end of each quarter. Although as of December 31, 2018 we were in compliance with the current ratio covenant, if we do not sufficiently reduce our capital expenditures in the future or obtain additional financing, including the issuance of additional Series B Preferred Stock, prior to our next borrowing base redetermination date, we may be required to seek a waiver from our lenders with respect to our compliance with our current ratio covenant. Our next scheduled redetermination date is April 1, 2019, although we have the right to request a redetermination prior to that date. See "Debt Agreements" below for a further discussion of our credit agreement, including our financial covenants.

Because we are the operator of a high percentage of our acreage, the timing and level of our capital spending is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGLs, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations. In addition, we may be required to reclassify some portion of our reserves currently booked as proved undeveloped reserves if such a deferral of planned capital expenditures means we will be unable to develop such reserves within five years of their initial booking.

In the event we make any acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital for that or other reasons, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt or equity securities, or other means.

Working Capital Analysis

We define working capital as current assets less current liabilities. At December 31, 2018 and December 31, 2017, we had a working capital surplus of $5.5 million and deficit of $59.9 million, respectively. We may continue to incur working capital deficits in the future due to liabilities incurred in connection with our drilling program until revenue is recognized from the associated production. Collection of our accounts receivable has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Cash and cash equivalents totaled $20.2 million and $20.7 million, at December 31, 2018 and December 31, 2017, respectively. Effective December 5, 2018, the borrowing base under our credit facility increased to $220 million, with borrowings of $194.0 million outstanding at December 31, 2018. We expect that the pace of development activities, production volumes, commodity prices and differentials to NYMEX prices for oil and natural gas production will be the most significant variables affecting our working capital.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows for the periods indicated:

	Year Ended December 31,		
	2018	**2017**	**2016**
	(In thousands)		
Net cash provided by operating activities	$ 176,309	$ 37,759	$ 11,461
Net cash used in investing activities	(399,343)	(265,497)	(22,164)
Net cash provided by (used in) financing activities	218,509	243,986	(8,597)
Net increase (decrease) in cash and cash equivalents	$ (4,525)	$ 16,248	$ (19,300)

Analysis of Cash Flow Changes for the Year Ended December 31, 2018 and 2017

Operating Activities. Net cash provided by operating activities is primarily driven by the changes in commodity prices, operating expenses, production volumes and associated changes in working capital. The increase in net cash provided by operating activities of $138.6 million was primarily due to an increase in production and realized prices increasing revenues by $225.6 million partially offset by an increase in cash related expenses of $72.2 million and an increase in loss on hedge settlements of $14.8 million.

Investing Activities. Net cash used in investing activities for the year ended December 31, 2018 included $377.9 million attributable to the development of oil and natural gas properties, $15.3 million for the acquisition of land and leasehold, royalty and mineral interests, $4.0 million for the release of the escrow deposit for the White Wolf Acquisition and $2.2 million for additions to other property and equipment. Net cash used in investing activities for the year ended December 31, 2017 primarily consisted of $114.8 million for the White Wolf Acquisition; $149.8 million for drilling and completion activities and facilities, which included $17.5 million for facilities, disposal and water wells and pipelines and $12.1 million associated with drilling and completion cost in progress; $6.5 million to acquire additional interest in wells we operate in Loving County and $0.6 million for other property and equipment. These amounts were partially offset by proceeds from our oil and natural gas properties dispositions of $6.3 million, which are primarily attributable to the net proceeds of $6.2 million from the Barnett Shale Asset Sale.

Financing Activities. Net cash provided by financing activities for the year endedDecember 31, 2018 primarily consists of net borrowings of$194.0 million under our Amended and Restated Credit Agreement and approximately $39.4 million from our Class A Common Stock Offering partially offset by $10.7 million of dividend payments and $3.3 million of debt issuance costs. Net cash provided by financing activities for 2017 included net cash of $230.8 million from the issuance of the Series A Preferred Stock and the Series B Preferred Stock, $97.0 million of proceeds from the Second Lien Notes and $18.7 million of proceeds from the Transaction. The cash provided by financing activity was partially offset by net cash payments on our credit facility of $55 million, distribution to our noncontrolling interest in the amount of $40.5 million, debt issuance costs of $4.6 million and a distribution to Tema in the amount of $2.3 million.

Analysis of Cash Flow Changes for the Year Ended December 31, 2017 and 2016

Operating Activities. Net cash provided by operating activities is primarily driven by the changes in commodity prices, operating expenses, production volumes and associated changes in working capital. The increase in net cash provided by operating activities of $26.3 million was primarily due to an increase in production and realized prices. Our total revenues increased by $41.6 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. Although we reported a net loss for the year ended December 31, 2017, a significant amount of the loss was attributable to DD&A which is non-cash as well as a mark-to-market loss on unsettled commodity derivative instruments.

Investing Activities. Net cash used in investing activities is primarily comprised of acquisition and development of oil and natural gas properties. Net cash used in investing activities for the year ended December 31, 2017 primarily consisted of $114.8 million for the White Wolf Acquisition; $149.8 million for drilling and completion activities and facilities, which included $17.5 million for facilities, disposal and water wells, and pipelines and $12.1 million associated with drilling and completion cost in progress; $6.5 million to acquire additional interest in wells we operate in Loving County and $0.6 million for other property and equipment. These amounts were partially offset by proceeds from our oil and natural gas properties dispositions of $6.3 million, which are primarily attributable to the net proceeds of $6.2 million from the Barnett Shale Asset Sale. In 2016, net cash used for investing activities included $22.0 million attributable to the acquisition and development of oil and natural gas properties.

Financing Activities. Net cash provided by financing activities increased by $252.6 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. Net cash provided by financing activities for 2017 included net cash of $230.8 million from the issuance of the Series A Preferred Stock and the Series B Preferred Stock, $97.0 million of proceeds from the Second Lien Notes and $18.7 million of proceeds from the Transaction. The cash provided by financing activity was partially offset by net cash payments on our credit facility of $55 million, distribution to our noncontrolling interest in the amount of $40.5 million, debt issuance costs of $4.6 million and distribution to the parent in the amount of $2.3 million. Net cash provided by financing activities in 2016 included $10.0 million of borrowings on Tema's secured line of credit, $20.0 million of repayments under Tema's secured line of credit and $1.4 million of parent investment.

Class A Common Stock Equity Offering

On September 27, 2018, we entered into an Underwriting Agreement with Citigroup Global Markets Inc., as representative of the Underwriters, for a public offering of 6,150,000 shares of common stock at a public offering price of $6.10 per share ($5.795 per share net of underwriting discount and commissions). Pursuant to the Underwriting Agreement, the Company granted the Underwriters a 30-day option to purchase up to an additional 922,500 shares of Class A Common Stock.

On October 2, 2018, upon the closing of the Class A Common Stock Offering, the Company issued 6,150,000 shares of Class A Common Stock. The Company's net proceeds from the Class A Common Stock Offering, net of underwriting discounts and commissions and offering costs, was $34.5 million. On October 5, 2018, the Underwriters exercised their option to purchase an additional 840,744 shares of Class A Common Stock at the Underwriters' price of $5.795 per share. The Company received net proceeds of approximately $4.9 million for the shares of Class A Common Stock sold pursuant to the exercise of the Underwriters' option. The Company contributed all of the net proceeds from the Class A Common Stock Offering and the exercise of the Underwriters' option to Rosehill Operating in exchange for Rosehill Operating Common Units.

Debt Agreements

Amended and Restated Credit Agreement. On March 28, 2018, Rosehill Operating and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, entered into the Amended and Restated Credit Agreement to refinance and replace Rosehill Operating's previous credit facility (the "Previous Credit Facility").

Pursuant to the terms and conditions of the Amended and Restated Credit Agreement, Rosehill Operating's line of credit and a letter of credit facility increased from up to $250 million under the Previous Credit Facility to up to $500 million under the Amended and Restated Credit Agreement, subject to a borrowing base that is determined semi-annually by the Lenders based upon Rosehill Operating's financial statements and the estimated value of its oil and gas properties, in accordance with the Lenders' customary practices for oil and gas loans. Rosehill Operating's initial borrowing base was $150 million, which represented an increase of $75 million from the borrowing base in effect under the Previous Credit Facility. The first redetermination under the Amended and Restated Credit Agreement occurred during the second quarter of 2018. Rosehill Operating and the Lenders each have the right to one interim unscheduled redetermination of the borrowing base between any two successive scheduled redeterminations. Our borrowing base increased from $150 million to $210 million on June 29, 2018 and then it increased to$220 million on December 5, 2018. Beginning in 2019, redeterminations will occur on April 1 and October 1. On March 28, 2019, the borrowing base was increased to $300 million. The borrowing base will be automatically reduced upon the issuance or incurrence of debt under senior unsecured notes or upon Rosehill Operating's or any of its subsidiaries' disposition of properties or liquidation of hedges in excess of certain thresholds. Amounts borrowed under the Amended and Restated Credit Agreement may not exceed the borrowing base. The Amended and Restated Credit Agreement also does not permit Rosehill Operating to borrow funds if, at the time of such borrowing, Rosehill Operating is not in pro forma compliance with the financial covenants. Additionally, Rosehill Operating's borrowing base may be reduced in connection with the subsequent redetermination of the borrowing base.

The amounts outstanding under the Amended and Restated Credit Agreement are secured by first priority liens on substantially all of Rosehill Operating's oil and natural gas properties and associated assets and all of the stock of Rosehill Operating's material operating subsidiaries that are guarantors of the Amended and Restated Credit Agreement. If an event of default occurs under the Amended and Restated Credit Agreement, JPMorgan Chase Bank, N.A. will have the right to proceed against the pledged capital stock and take control of substantially all of Rosehill Operating and Rosehill Operating's material operating subsidiaries that are guarantors' assets. There are currently no guarantors under the Amended and Restated Credit Agreement.

Borrowings under the Amended and Restated Credit Agreement will bear interest at a base rate plus an applicable margin ranging from 1.00% to 2.00% or at LIBOR plus an applicable margin ranging from 2.00% to 3.00%. The Amended and Restated Credit Agreement will mature on August 31, 2022, with an automatic extension to March 28, 2023 upon the payment in full of the Second Lien Notes if there is no event of default under the senior secured credit facility during the time of such extension.

The Amended and Restated Credit Agreement contains various affirmative and negative covenants. These negative covenants may limit Rosehill Operating's ability to, among other things: incur additional indebtedness; make loans to others; make investments; enter into mergers; make or declare dividends or distributions; enter into commodity hedges exceeding a specified percentage of Rosehill Operating's expected production; enter into interest rate hedges exceeding a specified percentage of Rosehill Operating's outstanding indebtedness; incur liens; sell assets; and engage in certain other transactions without the prior consent of JPMorgan Chase Bank, N.A. and/or lenders.

The Amended and Restated Credit Agreement also requires Rosehill Operating to maintain compliance with the following financial ratios:

- a current ratio, which is the ratio of consolidated current assets (including unused commitments under the Amended and Restated Credit Agreement, but excluding certain non-cash assets) to consolidated current liabilities (excluding certain non-cash obligations, current maturities under the Amended and Restated Credit Agreement and the Note Purchase Agreement (as defined below)), of not less than 1.0 to 1.0,

- a leverage ratio, which is the ratio of the sum of Total Debt to Annualized EBITDAX (as such terms are defined in the Amended and Restated Credit Agreement) for the four fiscal quarters then ended, of not greater than 4.0 to 1.0 (the calculation of which will be modified once the Second Lien Notes and the Series B Redeemable Preferred Stock are no longer outstanding) and

- a coverage ratio, which is the ratio of EBITDAX to the sum of Interest Expense plus the aggregate amount of certain Restricted Payments (as such terms are defined in the Amended and Restated Credit Agreement) made during the preceding four fiscal quarters, of not less than 2.5 to 1.0 (such ratio expiring once the Series B Redeemable Preferred Stock are no longer outstanding).

We were in compliance with the current ratio, leverage ratio and coverage ratio in the Amended and Restated Credit Agreement for the measurement period ended December 31, 2018.

For additional information regarding our Amended and Restated Credit Agreement, see Note 10 - *Long-term Debt, net* in the consolidated financial statements under Part II, Item 8 of this Annual Report on Form 10-K.

Second Lien Notes. On December 8, 2017, Rosehill Operating issued and sold $100,000,000 in aggregate principal amount of 10.00% Senior Secured Second Lien Notes due January 31, 2023 to EIG Global Energy Partners, LLC ("EIG") under and pursuant to the terms of the Note Purchase Agreement, among Rosehill Operating and us, the holders of the Second Lien Notes party thereto (the "Holders") and U.S. Bank National Association, as agent and collateral agent on behalf of the Holders. The Second Lien Notes were issued and sold to the Holders in a private placement exempt from the registration requirements under the Securities Act.

Under the Note Purchase Agreement, Rosehill Operating may, at its option, redeem the Second Lien Notes in whole or in part, together with accrued and unpaid interest thereon, (i) at any time after December 8, 2019 but on or prior to December 8, 2020, at a redemption price equal to 103% of the principal amount of the Second Lien Notes being redeemed, (ii) at any time after December 8, 2020 but on or prior to December 8, 2021, at a redemption price equal to 101.5% of the principal amount of the Second Lien Notes being redeemed and (iii) at any time after December 8, 2021, at a redemption price equal to the principal amount of the Second Lien Notes being redeemed. On or prior to December 8, 2019, Rosehill Operating may, at its option, redeem the Second Lien Notes in whole or in part, together with accrued and unpaid interest thereon, at a redemption price equal to 103% of the principal amount of the Second Lien Notes being redeemed plus an additional make-whole premium set forth in the Note Purchase Agreement.

The Second Lien Notes may become subject to redemption under certain other circumstances, including upon the incurrence of non-permitted debt or, subject to various exceptions, reinvestments rights and prepayment or redemption rights with respect to other debt or equity of Rosehill Operating, upon an asset sale, hedge termination or casualty event. Rosehill Operating will be further required to make an offer to redeem the Second Lien Notes upon a Change in Control (as defined in the Note Purchase Agreement) at a redemption price equal to 101% of the principal amount being redeemed. Other than in connection with a change in control or casualty event, the redemption prices and make-whole premium described in the foregoing paragraph shall also apply, at such times and to the extent set forth therein, to any mandatory redemption of the Second Lien Notes or any acceleration of the Second Lien Notes prior to the stated maturity thereof upon the occurrence of an event of default.

The Note Purchase Agreement requires Rosehill Operating to maintain a leverage ratio, which is the ratio of the sum of all of Rosehill Operating's Total Debt to Annualized EBITDAX (as such terms are defined in the Note Purchase Agreement) for the four fiscal quarters then ended, of not greater than 4.00 to 1.00. We were in compliance with the leverage ratio for the measurement period ended December 31, 2018.

The Note Purchase Agreement contains various affirmative and negative covenants, events of default and other terms and provisions that are based largely on the Amended and Restated Credit Agreement, with a number of important modifications reflecting the second lien nature of the Second Lien Notes and certain other terms that were agreed to with the Holders. The negative covenants may limit Rosehill Operating's ability to, among other things, incur additional indebtedness (including pursuant to senior unsecured notes), make investments, make or declare dividends or distributions, redeem its preferred equity, acquire or dispose of oil and gas properties and other assets or engage in certain other transactions without the prior consent of the Holders, subject to various exceptions, qualifications and value thresholds. Rosehill Operating is also required to meet minimum commodity hedging levels based on its expected production on an ongoing basis.

We are subject to certain limited restrictions under the Note Purchase Agreement, including (without limitation) a negative pledge with respect to our equity interests in Rosehill Operating and a contingent obligation to guarantee the Second Lien Notes upon request by the Holders in the event that we incur debt obligations. The obligations of Rosehill Operating under the Note Purchase Agreement are secured on a second-lien basis by the same collateral that secures its first-lien obligations. In connection with the Notes Purchase Agreement, Rosehill Operating granted first-lien and second-lien security interests over additional collateral to meet the minimum mortgage requirements under the Note Purchase Agreement.

Preferred Stock and Warrants

We are authorized to issue up to 1,000,000 shares of our preferred stock, of which 150,000 have been designated as Series A Preferred Stock and 210,000 have been designated as Series B Preferred Stock. On April 27, 2017, we issued 75,000 shares of Series A Preferred Stock and 5,000,000 warrants (exercisable for shares of Class A Common Stock) in a private placement to certain qualified institutional buyers and accredited investors for net proceeds of $70.8 million. We issued an additional 20,000 shares of Series A Preferred Stock to Rosemore Holdings, Inc. and KLR Sponsor in connection with the closing of the Transaction for an additional $20.0 million.

On December 8, 2017, in connection with the White Wolf Acquisition, we issued 150,000 shares of Series B Preferred Stock, par value of $0.0001 per share, to EIG (the "Series B Preferred Stock Purchasers") for an aggregate purchase price of $150.0 million, less transaction costs and up-front fees of approximately $10.0 million. We had the option, subject to certain conditions, to sell from time to time up to an additional 50,000 shares of Series B Preferred Stock, in the aggregate, to the Series B Preferred Stock Purchasers and their transferees for a purchase price of $1,000 per share of Series B Preferred Stock. Such option terminated on December 8, 2018.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2018 is provided in the following table:

	2019	2020	2021	2022	2023	Thereafter	Total
				(In thousands)			
Second Lien Notes (1)	$ 10,139	$ 10,167	$ 10,139	$ 10,139	$ 100,861	$ —	$ 141,445
Credit Agreement (1)	10,449	10,478	10,449	196,319	—	—	227,695
Operating lease obligations	1,213	1,202	1,097	557	—	—	4,069
Capital lease obligations	34	3	—	—	—	—	37
Asset retirement obligations (2)	—	—	—	—	—	13,524	13,524
Series B Preferred Stock dividends and return (3)	15,674	15,717	15,674	15,674	195,578	—	258,317
Drilling commitments (4)	6,525	—	—	—	—	—	6,525
Minimum volume commitment	$ 1,692	$ 1,692	$ 1,526	$ 380	$ —	$ —	$ 5,290
Total	$ 45,726	$ 39,259	$ 38,885	$ 223,069	$ 296,439	$ 13,524	$ 656,902

(1) Includes both principal and interest. Interest expense was calculated on our Second Lien Notes using its stated interest rate of 10% and on our credit agreement using its weighted average interest rate of 5.3% as of December 31, 2018.

(2) Amounts represent estimates of our future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment.

(3) Includes liquidation preference of $156.7 million outstanding as of December 31, 2018 plus the return necessary to achieve a 16% internal rate of return ("IRR"). The holders of the Series B Preferred Stock may cause us to redeem all or a portion of the Series B Preferred Stock on or after December 8, 2023; therefore, we assumed a redemption on December 8, 2023.

(4) We had 2 drilling rigs under contract as of December 31, 2018 of less than one year for each. Early termination of such contracts would have resulted in termination penalties of $3.5 million, which would have been payable as of December 31, 2018 in lieu of the remaining drilling commitments under the contracts. These amounts only include daily drilling rates and not costs such as reimbursement of fees that we may incur from the contractor.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2018, 2017 and 2016. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and in the past, we have tended to experience inflationary pressure on the cost of midstream and oilfield services and equipment when oil and natural gas prices increase due to the demand for their services as drilling activity in our areas of operations increase.

Off-Balance Sheet Arrangements

As of December 31, 2018, we had no off-balance sheet arrangements.

Recently Issued Accounting Pronouncements

Please refer to Note 2 - *Summary of Significant Accounting Policies and Recently Issued Accounting Standards* in the consolidated financial statements under Part II, Item 8 of this Annual Report on Form 10-K for a discussion of recent accounting pronouncements and their anticipated effect on us.

Critical Accounting Policies and Estimates

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

Oil and natural gas exploration, development and production activities are accounted for under the successful efforts method of accounting. Under this method, the costs incurred to acquire, drill and complete productive wells and development wells are capitalized. Oil and gas lease acquisition costs are also capitalized.

Proved Oil and Natural Gas Properties. If proved reserves are found for these properties, costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil, natural gas, and NGLs are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells, and service wells, including unsuccessful development wells, are capitalized. Capitalized costs attributed to the properties and mineral interests are subject to depreciation, depletion and amortization ("DD&A"). Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated reservoir. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense.

Unproved Properties. Acquisition costs associated with the acquisition of non-producing leaseholds are recorded as unproved leasehold costs and capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or right in a property, such as a lease in addition to options to lease, broker fees, recording fees and other similar costs related to acquiring properties. Leasehold costs are classified as unproved until proved reserves are discovered, at which time related costs are transferred to proved oil and natural gas properties.

Exploration Costs. Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include exploratory seismic expenditures, other geological and geophysical costs and lease rentals. The costs of drilling exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending determination of whether the well has discovered proved commercial reserves. If the exploratory well is determined to be unsuccessful, the cost of the well is transferred to expense.

In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a 12-month period after drilling is complete.

For sales of a complete or partial unit of proved and unproved properties and related facilities, the cost and related accumulated DD&A are removed from the property accounts and gain or loss is recognized for the difference between the proceeds received and the net carrying value of the properties sold.

Impairment of Oil and Natural Gas Properties

Our proved oil and natural gas properties are recorded at cost. Our proved properties are evaluated for impairment on a field-by-field basis whenever events or changes in circumstances indicate that an asset's carrying value may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on its estimate of future oil and natural gas prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using WTI and Henry Hub natural gas NYMEX strip market pricing, adjusted for quality, transportation fees and a regional price differential. While it is difficult to project future impairment write-downs in light of numerous factors involved, fluctuations in prices or costs could result in an impairment of our oil and natural gas properties.

Unproved oil and natural gas properties are assessed periodically, and no less than annually, for impairment on an aggregate basis based on remaining lease term, drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. As unproved oil and natural gas properties are developed and reserves are proved, the capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved oil and natural gas properties are written off or reclassified to proved oil and natural gas properties depends on the timing and success of our future exploration and development program.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depreciation, depletion and amortization expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease, respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Oil and gas properties are grouped based upon a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Depreciation, depletion and amortization rates are updated quarterly to reflect the addition of capital costs, reserve revisions (upwards or downwards) and additions, property acquisitions and/or property dispositions and impairments.

Oil and Natural Gas Reserve Quantities

Our estimated proved reserve quantities and future net cash flows are critical to the understanding of the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in its financial statements, including the calculations of depletion and impairment of proved oil and natural gas properties. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10% discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We have and expect to evaluate and estimate our proved reserves each year-end. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with U.S. GAAP for the impact of additions and dispositions.

Asset Retirement Obligations

An asset retirement obligation (“ARO”) represents the estimated present value of the amount we will incur to retire a long-lived asset at the end of its productive life, in accordance with applicable state laws. We recognize an estimated liability for future costs primarily associated with the abandonment of our oil and natural gas properties and related assets. The amount of the ARO is determined by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value at inception (i.e., at the time the well is drilled or acquired and related assets are placed into service) with an offsetting increase in the carrying amount of the related long-lived asset that is included in proved oil and natural gas properties in the accompanying consolidated balance sheets. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. We depreciate the long-lived asset, including the asset retirement cost, over its useful life and recognize an expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties.

Asset retirement liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of assets and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions, the costs to ultimately retire our wells may vary significantly from prior estimates.

Commodity Derivative Instruments

We utilize commodity derivative instruments including swaps, collars, basis swaps and other similar agreements to manage our exposure to oil and natural gas price volatility (i.e., price risk) associated with the forecasted sale of a portion of our oil and natural gas production. These commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, we record derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and record the change in the fair value of derivatives in current earnings in the statements of operations as they occur in the period of change. Gains and losses on commodity derivatives and premiums paid for put options are included in cash flows from operating activities.

To the extent a legal right of offset exists with a counterparty, we report derivative assets and liabilities on a net basis. We have exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. We actively monitor the creditworthiness of counterparties and assesses the impact, if any, on our derivative position.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for oil, natural gas and NGLs production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to occur in the future. The prices we receive for oil, natural gas, and NGLs production depend on numerous factors beyond our control.

To achieve a more predictable cash flow and reduce exposure to adverse fluctuations in commodity prices, we have historically used commodity derivative instruments, such as swaps, two-way costless collars and three-way costless collars, to hedge price risk associated with a portion of our anticipated oil and natural gas production. By removing a significant portion of the price volatility associated with our oil and natural gas production, we mitigate, but do not eliminate, the potential negative effects of declines in benchmark oil and natural gas prices on our cash flow from operations for those periods. We are obligated under our Note Purchase Agreement to hedge a specific portion of our production. See more information on our derivative activity in Item 7 of Part II, specifically the information set forth under the caption *"Derivative Activity*."

Counterparty Exposure and Customer Credit Risk

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our commodity derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. The counterparties to our commodity derivative contracts currently in place have investment grade ratings.

Our principal exposures to credit risk are through receivables resulting from joint interest receivables and receivables from the sale of our oil and natural gas production due to the concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, the credit quality of our customers is believed to be high.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells.

Our hedging policy permits us to enter into derivative contracts with major financial institutions or major energy entities. Our derivative contracts are currently with major financial institutions as lenders under our Amended and Restated Credit Agreement. We have rights of offset against the borrowings under our Amended and Restated Credit Agreement.

Interest Rate Risk

As of December 31, 2018, we had $194.0 million outstanding under the Amended and Restated Credit Agreement with a weighted average interest rate of 5.3%. Interest under the Amended and Restated Credit Agreement is tiered based on amount borrowed. The interest rate is LIBOR plus a range of 2% to 3% depending on the outstanding balance. Assuming no change in the amount outstanding, the impact on annual interest expense of a 1% increase or decrease in the assumed weighted average interest rate would be approximately $1.9 million. We currently have no derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness. Our Second Lien Notes have a fixed interest rate of 10.0%.

During 2017, policymakers announced that LIBOR will be replaced by SOFR by 2021. The new benchmark rate will be based on overnight Treasury General Collateral repossession rates. We will monitor the continuous emergence of SOFR, as it could adversely impact our interest rate risk, and therefore the amount of interest we pay on liabilities currently measured at LIBOR.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Rosehill Resources, Inc.
Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Rosehill Resources, Inc. (the "Company") and its subsidiary as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders' equity/parent net investment 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 Company and its subsidiary at December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company 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 consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2016.

Houston, Texas
March 28, 2019

ROSEHILL RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

		December 31, 2018		December 31, 2017
ASSETS				
Current assets:				
Cash and cash equivalents	$	20,157	$	20,677
Restricted cash		—		4,005
Accounts receivable		32,260		1,527
Accounts receivable, related parties		78		16,022
Derivative assets		30,819		—
Prepaid and other current assets		1,371		1,312
Total current assets		84,685		43,543
Property and equipment:				
Oil and natural gas properties (successful efforts), net		666,797		431,332
Other property and equipment, net		2,592		1,283
Total property and equipment, net		669,389		432,615
Other assets, net		4,678		824
Derivative assets		58,314		—
Total assets	$	817,066	$	476,982
LIABILITIES, MEZZANINE EQUITY AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	21,013	$	31,868
Accounts payable, related parties		287		223
Derivative liabilities		—		10,772
Accrued liabilities and other		27,335		15,492
Accrued capital expenditures		30,529		45,045
Total current liabilities		79,164		103,400
Long-term liabilities:				
Long-term debt, net		288,298		93,199
Asset retirement obligations, net of current portion		13,524		8,522
Deferred tax liabilities		9,278		153
Derivative liabilities		696		8,008
Other liabilities		3,658		168
Total long-term liabilities		315,454		110,050
Total liabilities		394,618		213,450
Commitments and contingencies (Note 16)				
Mezzanine equity				
Series B Preferred Stock; $0.0001 par value, 10.0% Redeemable, $1,000 per share liquidation preference; of the 1,000,000 shares of Preferred Stock authorized, 210,000 shares designated, 156,746 and 150,626 shares issued and outstanding as of December 31, 2018 and 2017, respectively		155,111		140,868
Stockholders' equity				
Series A Preferred Stock; $0.0001 par value, 8.0% Cumulative Perpetual Convertible, $1,000 per share liquidation preference; of the 1,000,000 shares of Preferred Stock authorized, 150,000 shares designated, 101,669 and 97,698 shares issued and outstanding as of December 31, 2018 and 2017, respectively		84,631		80,660
Class A Common Stock; $0.0001 par value, 250,000,000 and 95,000,000 shares authorized at December 31, 2018 and 2017, respectively, and 13,760,136 and 6,222,299 shares issued and outstanding as of December 31, 2018 and 2017, respectively		1		1
Class B Common Stock; $0.0001 par value, 30,000,000 shares authorized, 29,807,692 shares issued and outstanding as of December 31, 2018 and 2017, respectively		3		3
Additional paid-in capital		42,271		29,946
Retained earnings		26,661		—
Total common stockholders' equity		68,936		29,950
Noncontrolling interest		113,770		12,054
Total stockholders' equity		267,337		122,664
Total liabilities, mezzanine and stockholders' equity	$	817,066	$	476,982

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	Year Ended December 31,		
	2018	2017	2016
Revenues:			
Oil sales	$ 271,539	$ 61,596	$ 24,807
Natural gas sales	9,392	7,171	5,304
Natural gas liquids sales	20,944	7,469	4,534
Total revenues	301,875	76,236	34,645
Operating expenses:			
Lease operating expenses	39,010	10,881	4,800
Production taxes	14,506	3,535	1,541
Gathering and transportation	4,939	2,976	2,398
Depreciation, depletion, amortization and accretion	141,815	36,091	24,965
Impairment of oil and natural gas properties	—	1,061	—
Exploration costs	4,374	1,747	794
General and administrative	30,469	13,428	6,166
Transaction costs	—	2,618	2,834
(Gain) loss on disposition of property and equipment	499	(4,995)	(50)
Total operating expenses	235,612	67,342	43,448
Operating income	66,263	8,894	(8,803)
Other income (expense):			
Interest expense, net	(19,489)	(2,532)	(1,822)
Gain (loss) on commodity derivative instruments, net	92,604	(16,336)	(4,169)
Other expense, net	(3,254)	(284)	(247)
Total other income (expense), net	69,861	(19,152)	(6,238)
Income (loss) before income taxes	136,124	(10,258)	(15,041)
Income tax expense	18,162	1,690	148
Net income (loss)	117,962	(11,948)	(15,189)
Net income (loss) attributable to noncontrolling interest	59,926	(18,811)	—
Net income attributable to Rosehill Resources Inc. before preferred stock dividends	58,036	6,863	(15,189)
Series A Preferred Stock dividends and deemed dividends	7,938	12,936	—
Series B Preferred Stock dividends, deemed dividends, and return	23,437	2,447	—
Net income (loss) attributable to Rosehill Resources Inc. common stockholders	$ 26,661	$ (8,520)	$ (15,189)
Earnings (loss) per common share:			
Basic	$ 3.25	$ (1.43)	$ (2.59)
Diluted	$ 1.76	$ (1.43)	$ (2.59)
Weighted average common shares outstanding:			
Basic	8,196	5,945	5,857
Diluted	46,499	5,945	5,857

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/PARENT NET INVESTMENT
(In thousands, except share amounts)

	Preferred Stock Series A		Common Stock									
			Class A		Class B							
	Shares	Value	Shares	Value	Shares	Value	Additional Paid-in Capital	Retained Earnings (Deficit)	Total Common Stockholders' Equity	Non-controlling Interest	Parent Net Investment	Total Equity
Balance at December 31, 2015	—	$ —	—	$ —	—	$ —	$ —	$ —	$ —	$ —	$ 78,977	$ 78,977
Net income (loss)	—	—	—	—	—	—	—	—	—	—	(15,189)	(15,189)
Distribution (to) from parent	—	—	—	—	—	—	—	—	—	—	1,432	1,432
Balance at December 31, 2016	—	$ —	—	$ —	—	$ —	$ —	$ —	$ —	$ —	$ 65,220	$ 65,220
Net distribution to parent	—	—	—	—	—	—	—	—	—	—	(2,267)	(2,267)
Net income (loss)	—	—	—	—	—	—	—	2,449	2,449	(18,811)	4,414	(11,948)
Effect of the Transaction:												
Issuance of preferred stock and warrants	95,000	70,594	—	—	—	—	20,186	—	20,186	—	—	90,780
Proceeds and shares obtained in the Transaction	—	—	5,856,581	1	29,807,692	3	7,447	—	7,451	78,604	(67,367)	18,688
Distribution to noncontrolling interest, net	—	—	—	—	—	—	—	—	—	(38,106)	—	(38,106)
Benefit from reversal of valuation allowance	—	—	—	—	—	—	1,537	—	1,537	—	—	1,537
Restricted shares granted to directors and employee service awards	—	—	119,456	—	—	—	—	—	—	—	—	—
Stock based compensation	—	—	—	—	—	—	1,245	—	1,245	—	—	1,245
Series A Preferred stock dividends	5,530	12,898	—	—	—	—	(10,487)	(2,449)	(12,936)	—	—	(38)
Series A Preferred stock conversions	(2,832)	(2,832)	246,262	—	—	—	2,832	—	2,832	—	—	—
Series B Preferred stock dividends, deemed dividends and return	—	—	—	—	—	—	(2,447)	—	(2,447)	—	—	(2,447)
Impact of transactions affecting noncontrolling interests	—	—	—	—	—	—	9,633	—	9,633	(9,633)	—	—
Balance at December 31, 2017	97,698	$80,660	6,222,299	$ 1	29,807,692	$ 3	$ 29,946	$ —	$ 29,950	$ 12,054	$ —	$ 122,664

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/PARENT NET INVESTMENT (continued)
(In thousands, except share amounts)

	Preferred Stock Series A		Common Stock Class A		Common Stock Class B						
	Shares	Value	Shares	Value	Shares	Value	Additional Paid-in Capital	Retained Earnings (Deficit)	Total Common Stockholders' Equity	Non-controlling Interest	Total Equity
Balance at December 31, 2017	97,698	$ 80,660	6,222,299	$ 1	29,807,692	$ 3	$ 29,946	$ —	$ 29,950	$ 12,054	$ 122,664
Net income (loss)	—	—	—	—	—	—	—	58,036	58,036	59,926	117,962
Adjustment to deferred taxes	—	—	—	—	—	—	6,119	—	6,119	—	6,119
Benefit from reversal of valuation allowance	—	—	—	—	—	—	2,912	—	2,912	—	2,912
Class A Common Stock Equity Offering, net of stock issuance costs	—	—	6,990,744	—	—	—	39,356	—	39,356	—	39,356
Restricted stock issued	—	—	640,814	—	—	—	—	—	—	—	—
Restricted stock withheld for taxes	—	—	(93,721)	—	—	—	(749)	—	(749)	—	(749)
Stock-based compensation	—	—	—	—	—	—	6,477	—	6,477	—	6,477
Series A Preferred Stock dividends	3,971	3,971	—	—	—	—	—	(7,938)	(7,938)	—	(3,967)
Series B Preferred Stock dividends, deemed dividends and return	—	—	—	—	—	—	—	(23,437)	(23,437)	—	(23,437)
Impact of transactions affecting noncontrolling interest	—	—	—	—	—	—	(41,790)	—	(41,790)	41,790	—
Balance at December 31, 2018	101,669	$ 84,631	13,760,136	$ 1	29,807,692	$ 3	$ 42,271	$ 26,661	$ 68,936	$ 113,770	$ 267,337

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	117,962	$ (11,948)	$ (15,189)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion, amortization, accretion and impairment of oil and gas properties	141,815	37,152	24,965
Deferred income taxes	18,157	1,690	—
Stock-based compensation	6,522	1,245	—
(Gain) loss on sale of fixed assets	499	(4,995)	(50)
(Gain) loss on derivative instruments	(92,534)	16,706	4,630
Net cash received (paid) in settlement of derivative instruments	(14,683)	74	(1,608)
Amortization of debt issuance costs	2,139	274	113
Settlement of asset retirement obligations	(801)	(840)	(53)
Tax Receivable Agreement Expense	3,518	—	—
Changes in operating assets and liabilities:			
(Increase) in accounts receivable and accounts receivable, related parties	(14,816)	(8,230)	(3,091)
(Increase) decrease in prepaid and other assets	(59)	(451)	53
Increase in accounts payable and accrued liabilities and other	8,526	7,476	1,691
Increase (decrease) in accounts payable, related parties	64	(394)	—
Net cash provided by operating activities	176,309	37,759	11,461
Cash flows from investing activities:			
Additions to oil and natural gas properties	(377,897)	(149,832)	(22,004)
Acquisition of White Wolf	(4,005)	(114,843)	—
Acquisition of land and leasehold, royalty and mineral interest	(15,281)	(6,500)	—
Additions to other property and equipment	(2,160)	(574)	(263)
Proceeds from sale of other property and equipment	—	6,252	103
Net cash used in investing activities	(399,343)	(265,497)	(22,164)
Cash flows from financing activities:			
Proceeds from revolving credit facility	274,000	66,000	10,000
Repayment on revolving credit facility	(80,000)	(121,000)	—
Repayment of long-term debt	—	—	(20,000)
Proceeds from Class A Common Stock offering	40,511	—	—
Class A Common Stock offering issuance costs	(1,155)		
Proceeds from issuance of Series A Preferred Stock and Warrants	—	95,000	—
Series A Preferred Stock issuance costs	—	(4,220)	—
Proceeds from issuance of Series B Preferred Stock	—	150,000	—
Series B Preferred Stock upfront fees and transaction costs	(20)	(10,017)	—
Proceeds from Second lien notes, net	—	97,000	—
Net proceeds from the Transaction	—	18,688	—
Distribution to noncontrolling interest	—	(40,487)	—
Distribution to Tema	—	(2,267)	1,432
Debt issuance costs	(3,330)	(4,640)	—
Dividends paid on preferred stock	(10,716)	(38)	—
Restricted stock used for tax withholdings	(749)	—	—
Payment on capital lease obligation	(32)	(33)	(29)
Net cash provided by (used in) financing activities	218,509	243,986	(8,597)
Net increase (decrease) in cash, cash equivalents, and restricted cash	(4,525)	16,248	(19,300)
Cash, cash equivalents, and restricted cash beginning of period	24,682	8,434	27,734
Cash, cash equivalents, and restricted cash end of period	$ 20,157	$ 24,682	$ 8,434

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(Unaudited)
(In thousands)

Supplemental cash flow information and noncash activity:

	Year Ended December 31,		
	2018	2017	2016
Supplemental disclosures:			
Cash paid for interest	$ 17,065	$ 1,889	$ 1,794
Supplemental noncash activity:			
Asset retirement obligations incurred	$ 4,697	$ 5,766	$ 1,641
Changes in accrued capital expenditures	14,516	42,602	(1,434)
Changes in accounts payable for capital expenditures	7,456	25,541	—
White Wolf Acquisition escrow deposit	—	4,005	—
Series A Preferred Stock dividends paid-in-kind	3,971	5,530	—
Series A Preferred Stock dividends declared and payable	1,015	—	—
Series B Preferred Stock dividends paid-in-kind	6,120	626	—
Series B Preferred Stock cash dividends declared and payable	2,347	937	—
Series B Preferred Stock return	6,798	710	—
Series B Preferred Stock deemed dividend	1,345	174	—

Reconciliation of cash, cash equivalents and restricted cash presented on the Consolidated Statement of Cash Flows:

	December 31,		
	2018	2017	2016
Cash and cash equivalents	$ 20,157	$ 20,677	$ 8,434
Restricted cash	—	4,005	—
Total cash, cash equivalents and restricted cash	$ 20,157	$ 24,682	$ 8,434

As of December 31, 2017, restricted cash was attributable to the White Wolf Acquisition purchase price in an escrow account. The full amount of the escrow account was released to the sellers in March 2018.

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

Note 1 – Organization and Basis of Presentation

Organization

Rosehill Resources Inc. (the "Company" or "Rosehill") is an independent oil and natural gas company focused on the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. The Company's assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin.

The Company was incorporated in Delaware on September 21, 2015 as a special purpose acquisition company under the name of KLR Energy Acquisition Corp. ("KLRE") for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination involving the Company and one or more businesses. On April 27, 2017, the Company acquired a portion of the equity of Rosehill Operating Company, LLC ("Rosehill Operating"), in a transaction structured as a reverse recapitalization (the "Transaction"), into which Tema Oil & Gas Company ("Tema"), a wholly owned subsidiary of Rosemore, Inc. ("Rosemore"), contributed certain assets and liabilities. At the closing of the Transaction, the Company became the sole managing member of Rosehill Operating. Following the Transaction, the Company changed its name to Rosehill Resources Inc.

As the sole managing member of Rosehill Operating, the Company, through its officers and directors, is responsible for all operational and administrative decision-making and control of all of the day-to-day business affairs of Rosehill Operating without the approval of any other member, unless specified in the Second Amended and Restated Limited Liability Company Agreement of Rosehill Operating (the "LLC Agreement").

Transaction

On April 27, 2017, upon closing the Transaction, the Company acquired a portion of the common units of Rosehill Operating (the "Rosehill Operating Common Units") for (i) the contribution to Rosehill Operating by the Company of $35 million in cash (the "Cash Consideration"), excluding the working capital adjustment, and the issuance to Rosehill Operating by the Company of 29,807,692 shares of its Class B Common Stock, (ii) the assumption by Rosehill Operating of $55 million in Tema indebtedness and (iii) the contribution to Rosehill Operating by the Company of the remaining cash proceeds of the Company's initial public offering net of redemptions of approximately $60.6 million. In connection with the closing of the Transaction, the Company issued to Rosehill Operating 4,000,000 warrants exercisable for shares of the Company's Class A Common Stock (the "Tema warrants") in exchange for 4,000,000 warrants exercisable for Rosehill Operating Common Units (the "Rosehill warrants"). The Cash Consideration, estimated working capital adjustment, Tema warrants and shares of Class B Common Stock were immediately distributed to Tema. The working capital adjustment was originally estimated to be $5.6 million and was contributed to Rosehill Operating by the Company upon closing the Transaction. The final working capital adjustment of $2.4 million due to the Company from Tema was reflected as a reduction to the preliminary purchase price.

In connection with the Transaction, the Company issued and sold 75,000 shares of its 8% Series A Cumulative Perpetual Convertible Preferred Stock (the "Series A Preferred Stock") and 5,000,000 warrants in a private placement to certain qualified institutional buyers and accredited investors (the "PIPE Investors") for net proceeds of $70.8 million (the "PIPE Investment"). The Company issued an additional 20,000 shares of Series A Preferred Stock to Rosemore Holdings, Inc. (wholly owned subsidiary of Rosemore) and KLR Energy Sponsor, LLC (the "Sponsor") in connection with the closing of the Transaction for net proceeds of $20 million. The Company contributed the net proceeds from the PIPE Investment and from the issuance of 20,000 shares of Series A Preferred Stock to Rosemore Holdings, Inc. and the Sponsor to Rosehill Operating in exchange for Rosehill Operating Series A Preferred Units and additional Rosehill warrants. Of these proceeds, $55 million was used to retire the indebtedness assumed by Rosehill Operating.

Net cash provided by the Company upon the closing of the Transaction was $109.5 million, which consisted of $90.8 million of net proceeds from the sale of Series A Preferred Stock and $18.7 million from the sale of common shares prior to the Transaction, net of redemptions and offering and transaction costs.

Basis of Presentation

The consolidated financial results of the Company consist of the financial results of Rosehill and Rosehill Operating, its consolidated subsidiary. Pursuant to the Transaction described above, the Company acquired approximately 16.4% of the Rosehill Operating Common Units, while Tema retained approximately 83.6% of the Rosehill Operating Common Units. As of December 31, 2018, the Company owns approximately 31.6% of the Rosehill Operating Common Units and Tema owns approximately 68.4% of the Rosehill Operating Common Units.

The Transaction was accounted for as a reverse recapitalization. As a result, the reports filed by the Company subsequent to the Transaction are prepared "as if" Rosehill Operating is the predecessor and legal successor to the Company. The historical operations of Rosehill Operating are deemed to be those of the Company. Thus, the financial statements included in this report reflect (i) the historical operating results of Rosehill Operating prior to the Transaction; (ii) the combined results of the Company and Rosehill Operating following the Transaction; (iii) the assets and liabilities of Rosehill Operating at their historical cost; and (iv) the Company's equity and earnings per share for all periods presented.

All periods prior to the date of the Transaction shown in the accompanying consolidated financial statements have been prepared on a "carve-out" basis and are derived from the accounting records of Tema. The accompanying consolidated financial statements prior to the Transaction include direct expenses related to Rosehill Operating and expense allocations for certain functions of Tema including, but not limited to, general corporate expenses related to finance, legal, information technology, human resources, communications, insurance, utilities and compensation. These expenses have been allocated on the basis of direct usage when identifiable, actual volumes and revenues, with the remainder allocated proportionately on a barrel of oil equivalent ("Boe") basis. Management considers the basis on which the expenses have been allocated to reasonably reflect the utilization of services provided to or the benefit received by Rosehill Operating during the periods presented. The allocations may not, however, reflect the expenses that would have been incurred as an independent company for the periods presented. Actual costs that may have been incurred prior to the Transaction would depend on a number of factors, including the organizational structure, whether functions were outsourced or performed by employees and strategic decisions made in areas such as information technology and infrastructure. The allocations and related estimates and assumptions are described more fully in Note 15 - *Transactions with Related Parties.*

The consolidated financial statements of the Company have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") and in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"). All intercompany balances and transactions have been eliminated in consolidation. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying consolidated financial statements. Such reclassifications had no impact on net income, cash flows or shareholders' equity previously reported.

Variable Interest Entities

Rosehill Operating is a variable interest entity. The Company determined that it is the primary beneficiary of Rosehill Operating as the Company is the sole managing member and has the power to direct the activities most significant to Rosehill Operating's economic performance as well as the obligation to absorb losses and receive benefits that are potentially significant. The Company consolidated 100% of Rosehill Operating's assets and liabilities and results of operations in the Company's consolidated financial statements. Although Tema had a larger ownership interest in Rosehill Operating, because it has disproportionately fewer voting rights, Tema is shown as a noncontrolling interest holder of Rosehill Operating. For further discussion, see Noncontrolling Interest in Note 13 - *Stockholders' Equity.*

Note 2 – Summary of Significant Accounting Policies and Recently Issued Accounting Standards

Use of Estimates

The preparation of the Company's consolidated financial statements requires the Company's management to make various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues, expenses and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously reported. The more significant areas requiring the use of assumptions, judgments and estimates include:

- the quantities and values of proved oil, natural gas and natural gas liquids ("NGLs") reserves used in calculating depletion and assessing impairment of oil and natural gas properties and related present value estimates of future net cash flows therefrom,

- the carrying value of oil and natural gas properties,
- impairment of oil and natural gas properties,
- asset retirement obligations,
- oil and natural gas reserve quantities,
- the fair value of commodity derivative instruments and positions,
- fair value of the Company's warrants,
- estimates of the fair value of equity-based compensation,
- estimates of current and deferred income taxes and
- deferred income tax valuation allowances and amounts associated with the Company's Tax Receivable Agreement with Tema (the "Tax Receivable Agreement") (see Note 12 – *Income Taxes)*.

While management believes these estimates are reasonable, changes in facts and assumptions, or the discovery of new information may result in revised estimates. Actual results could differ from these estimates and it is reasonably possible these estimates could be revised in the near term, and these revisions could be material.

Cash and Cash Equivalents

The Company considers all cash on hand, and highly liquid instruments with an original maturity of three months or less to be cash and cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that may exceed the insurance limits of the Federal Deposit Insurance Corporation, however, management believes the Company's counter-party risks are minimal based on the reputation and history of the institutions selected.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments are received within three months after the production date. Accounts receivable are not collateralized.

Amounts due from joint interest owners or purchasers are stated net of an allowance for doubtful accounts when the Company believes collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2018 or December 31, 2017. See details of the Company's accounts receivable balance in Note 4 - *Accounts Receivable*.

Revenue Recognition

The Company derives its revenue primarily from the sale of produced oil, natural gas, and NGLs. Revenue is recognized when the Company's production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month, the Company make estimates of the amount of production delivered to the purchaser and the price it will receive. The Company uses its knowledge of its properties, contractual arrangements, NYMEX and local spot market prices, and other factors as the basis for these estimates. Variances between the estimates and the actual amounts received are recorded in the month payment is received. Transportation expenses for oil are included as a reduction to oil revenues, while gathering and transportation expenses for natural gas and NGLs are recorded within gathering and transportation. See *Recently Issued Accounting Standards Not Yet Adopted* within Note 2 for an update on the impact of ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*

("ASC 606"), on how the Company will recognize revenue in 2019 and beyond. The table below presents percentages by purchaser that accounted for 10% or more of our total oil, natural gas and NGL sales for each year as presented:

	Year Ended December 31,		
	2018	**2017**	**2016**
Customer			
Gateway (1)	60%	80%	70%
Plains	17	—	—
Targa	13	—	—
ETC Field Services, LLC	—	10	17
Enlink Midstream Services, LLC	—	—	10
Other	10	10	3
Total	100%	100%	100%

(1) For a further discussion see Note 15 - *Related Party Transactions*

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

Oil and natural gas exploration, development and production activities are accounted for under the successful efforts method of accounting. Under this method, the costs incurred to acquire, drill and complete productive wells and development wells are capitalized. Oil and gas lease acquisition costs are also capitalized.

Proved Oil and Natural Gas Properties. If proved reserves are found for these properties, costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil, natural gas and NGLs are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells and service wells, including unsuccessful development wells, are capitalized. Capitalized costs attributed to the properties and mineral interests are subject to depreciation, depletion and amortization ("DD&A"). Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated reservoir. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense.

Unproved Properties. Acquisition costs associated with the acquisition of non-producing leaseholds are recorded as unproved leasehold costs and capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or right in a property, such as a lease in addition to options to lease, broker fees, recording fees and other similar costs related to acquiring properties. Leasehold costs are classified as unproved until proved reserves are discovered, at which time related costs are transferred to proved oil and natural gas properties.

Exploration Costs. Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include personnel and other internal costs, geological and geophysical expenses, exploratory dry holes, delay rentals for leases and cost associated with unsuccessful lease acquisitions. The costs of drilling exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending determination of whether the well has discovered proved commercial reserves. If the exploratory well is determined to be unsuccessful, the cost of the well is transferred to expense.

In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a 12-month period after drilling is complete.

For sales of a complete or partial unit of proved and unproved properties and related facilities, the cost and related accumulated DD&A are removed from the property accounts and gain or loss is recognized for the difference between the proceeds received and the net carrying value of the properties sold.

Impairment of Oil and Natural Gas Properties

The Company's proved oil and natural gas properties are recorded at cost. The Company's proved properties are evaluated for impairment on a field-by-field basis whenever events or changes in circumstances indicate that an asset's carrying value may not be recoverable. The Company compares expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on its estimate of future oil and natural gas prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using WTI and Henry Hub natural gas NYMEX strip market pricing, adjusted for quality, transportation fees and a regional price differential. Fair value is calculated by discounting the future cash flows at a rate of 10%. The Company believes a 10% discount rate is commonly used by oil and gas industry peers, analysts and investors in evaluating the monetary significance of oil and gas properties and for comparing the size and value of proved reserves among companies in our industry. Accordingly, the Company currently believes a 10% discount rate is consistent with a rate a market participant would consider in evaluating onshore domestic proved oil and gas reserves and produces a reasonable estimate of fair value.

Unproved oil and natural gas properties are assessed periodically, and no less than annually, for impairment on an aggregate basis based on remaining lease term, drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. As unproved oil and natural gas properties are developed and reserves are proved, the capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved oil and natural gas properties are written off or reclassified to proved oil and natural gas properties depends on the timing and success of the Company's future exploration and development program.

Oil and Natural Gas Reserve Quantities

The Company's estimated proved reserve quantities and future net cash flows are critical to the understanding of the value of its business. They are used in comparative financial ratios and are the basis for significant accounting estimates in its financial statements, including the calculations of depletion and impairment of proved oil and natural gas properties. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10% discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, the Company makes a considerable effort in estimating our reserves. The Company expects proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. The Company has and expects to evaluate and estimate its proved reserves each year-end. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with U.S. GAAP for the impact of additions and dispositions.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, buildings, computer hardware and software is recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets ranging from three to twenty years. Major renewals and improvements are capitalized while expenditures for maintenance and repairs are expensed as incurred. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Asset Retirement Obligations

An asset retirement obligation ("ARO") represents the estimated present value of the amount a company will incur to retire a long-lived asset at the end of its productive life, in accordance with applicable state laws. The Company recognizes an estimated liability for future costs primarily associated with the abandonment of its oil and natural gas properties and related assets. The amount of the ARO is determined by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value at inception (i.e. at the time the well is drilled or acquired and related assets are placed into service) with an offsetting increase in the carrying amount of the related long-lived asset that is included in proved oil and natural gas properties in the accompanying consolidated balance sheets. Periodic accretion of discount of the estimated liability is recorded as an expense in the consolidated statement of operations. The Company depreciates the long-lived asset, including the asset retirement cost, over its useful life, and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties.

An asset retirement liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of assets and the Company's risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions, the costs to ultimately retire the Company's wells may vary significantly from prior estimates. See Note 8 - *Asset Retirement Obligations* for a further discussion.

Deferred Financing Costs

Deferred financing costs and discounts related to the Company's Revolving Credit Facility and its Second Lien Notes are included in other long-term assets and long-term debt, respectively, in the consolidated balance sheets and are stated at cost, net of amortization. The deferred financing costs associated with the Revolving Credit Facility and the Second Lien Notes are amortized to interest expense on a straight-line basis and an effective rate of interest method, respectively, over the borrowing terms. See Note 10 - *Long term debt, net* for a further discussion.

Commodity Derivative Instruments

The Company utilizes commodity derivative instruments including swaps, collars, basis swaps and other similar agreements to manage its exposure to oil, natural gas and NGL price volatility (i.e., price risk) associated with the forecasted sale of a portion its oil and natural gas production. These commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the Company records derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings in the consolidated statements of operations as they occur in the period of change. Gains and losses on commodity derivatives and premiums paid for put options are included in cash flows from operating activities.

To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative position. See Note 5 - *Derivative Instruments* for a further discussion.

Fair Value of Financial Instruments

Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants at the reporting date. The Company's assets and liabilities that are measured at fair value at each reporting date are classified according to a hierarchy that prioritizes inputs and assumptions underlying the valuation techniques. This fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs and consists of three broad levels:

***Level 1*:**	Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
***Level 2*:**	Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable as of the reporting date.
***Level 3*:**	Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. See Note 6 – *Fair Value Measurements* for more fair value disclosures.

Income Taxes

The Company accounts for income taxes using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change.

The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return, which are subject to examination by federal and state taxing authorities. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties. The Company recognizes penalties and interest related to uncertain tax positions within the provision (benefit) for income taxes line in the accompanying consolidated statements of operations.

Rosehill Operating, the Company's accounting predecessor, is a limited liability company treated as a partnership for U.S. federal income tax purposes that is not subject to U.S. federal income tax.

Earnings (Loss) Per Share

The two-class method of computing earnings per share is required for entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Our Class B Common Stock has no economic interest in the earnings of the Company. Basic earnings (loss) per common share is calculated by dividing net income (loss) attributable to common shareholders by the weighted average number of shares of Class A Common Stock outstanding each period. Diluted earnings per share adds to those shares the incremental shares that would have been outstanding assuming exchanges of the Company's outstanding Class B Common Stock, Series A Preferred Stock and warrants for Class A Common Stock, and the vesting of unvested restricted stock units of Class A Common Stock. An anti-dilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

The Company uses the "if-converted" method to determine the potential dilutive effect of conversions of its outstanding Class B Common Stock and Series A Preferred Stock, and the treasury stock method to determine the potential dilutive effect of its outstanding warrants exercisable for shares of Class A Common Stock and the vesting of unvested restricted stock units of Class A Common Stock. See Note 3 - *Earnings Per Share* for the Company's earnings (loss) per share calculation.

Accounting Standards Adopted in 2018

Equity-based Compensation. In May 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-09 – *Compensation – Stock Compensation (Topic 718); Scope of Modification Accounting.* The new guidance clarifies when to account for a change to the terms or conditions of a share-based payment award as a modification. Under the new guidance, modification accounting is required only if the fair value, the vesting conditions, or the classification of the award as equity or liability changes as a result of the change in terms or conditions. The Company adopted ASU 2017-09 in 2018. The adoption of ASU 2017-09 did not have a material impact on the Company's consolidated financial statements for the year ended December 31, 2018.

Recently Issued Accounting Standards Not Yet Adopted

Revenue Recognition. ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASC 606"), supersedes the revenue recognition requirements in *Topic 605, Revenue Recognition*, and industry-specific guidance in *Subtopic 932-605, Extractive Activities-Oil and Gas-Revenue Recognition* and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients*, as clarifying guidance to improve the operability and understandability of the implementation guidance on principal versus agent considerations.

ASC 606 became effective for the Company on January 1, 2019, and the Company has elected to adopt it using the modified retrospective method. The Company has substantially completed its review of the impact of ASC 606 on its significant contracts and determined that upon adoption of ASC 606, the Company will not be required to record a cumulative effect adjustment due to ASC 606 not having a quantitative impact compared to existing GAAP. While the Company does not expect 2019 net income (loss) or cash flows from operations to be impacted by the implementation of ASC 606, there will be certain changes to the presentation of revenues and related expenses beginning January 1, 2019. Prior to adoption, the Company recorded all gathering and processing fees incurred for natural gas and NGLs in "Gathering and transportation." Upon adoption of ASC 606, where the Company delivers raw gas to midstream processing companies and retains control of its natural gas and plant products until tailgate of the plant, the cost of such gathering and processing will continue to be reflected in the Company's "Gathering and transportation" as has been its practice historically. In the case where the Company delivers raw gas to the midstream processing companies and transfer control of its raw natural gas at the inlet to the midstream processing companies, such costs will be reported as a reduction to "Natural gas sales" and "Natural gas liquids sales."

Financial Assets and Financial Liabilities. In January 2016, the FASB issued ASU 2016-01, *Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. The pronouncement requires, among other things, public business entities to use the exit price notion when measuring the fair value of financial instruments for disclosure purposes and requires separate presentation of financial assets and financial liabilities by measurement category and form of financial asset. For the Company, these changes become effective for fiscal years beginning after December 15, 2018. In February 2018, the FASB issued ASU 2018-03, *Technical Corrections and Improvements to Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*, which clarifies certain aspects of the guidance issued in ASU 2016-01 including: the ability to irrevocably elect to change the measurement approach for equity securities measured using the practical expedient (at cost plus or minus observable transactions less impairment) to a fair value method in accordance with Topic 820, Fair Value Measurement; clarification that if an observable transaction occurs for such securities, the adjustment is as of the observable transaction date; clarification that the prospective transition approach for equity securities without a readily determinable fair value is meant only for instances in which the practical expedient is elected; and various other clarifications. The expected adoption of ASU 2016-01 and ASU 2018-03 are being evaluated by the Company and the adoption is not expected to have a significant impact on the Company's consolidated financial statements.

Leases. In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* which requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under current U.S. GAAP. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842*, which provides clarifying guidance regarding land easements and adds practical expedients. In July 2018, further amendments were issued under ASU 2018-10, *Codification Improvements to Topic 842, Leases.* In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842): Targeted Improvements*, which provides entities with an additional transition method in which an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. ASU 2016-02 and its related updates are effective for the Company for fiscal years beginning after December 15, 2019. The Company is currently evaluating the method of adoption and the impact of the adoption of this guidance on its consolidated financial statements and disclosures.

Financial Instruments – Credit Losses. In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* requiring the measurement of all expected credit losses for financial assets, which include trade receivables, held at the reporting date based on historical experience, current conditions and reasonable and supportable forecasts. The guidance in this ASU is effective for the Company for fiscal years beginning after December 15, 2020, and interim periods within fiscal years beginning after December 15, 2021 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The evaluation of this standard and its impact on the Company's consolidated financial statements and related disclosures is currently being assessed.

Derivatives and Hedging. In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*, which expands and refines hedge accounting for both financial and non-financial risk components, aligns the recognition and presentation of the effects of hedging instruments and hedge items in the financial statements, and includes certain targeted improvements to ease the application of current guidance related to the assessment of hedge effectiveness. ASU 2017-12 is effective for the Company for fiscal years beginning after December 15, 2019. Early adoption is permitted. The Company is currently evaluating the impact of the adoption of this guidance on its consolidated financial statements.

Fair Value Measurement Disclosures. In August 2018, the FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*, which removes, modifies and adds disclosure requirements on fair value measurements. ASU 2018-13 is effective for the Company for fiscal years beginning after December 15, 2019 and the Company is permitted to early adopt any removed or modified disclosures upon issuance of this ASU and delay adoption of the additional disclosures until their effective date. The Company is currently evaluating the impact of the adoption of this guidance on its disclosures.

Note 3 – Earnings (Loss) Per Share

The Transaction was structured as a reverse recapitalization by which the Company issued stock for the net assets of Rosehill Operating accompanied by a recapitalization. Earnings per share has been recast for all historical periods to reflect the Company's capital structure for all comparative periods.

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands, except per share data)		
Net income (loss) (numerator):			
Net income (loss) attributable to common stockholders of Rosehill Resources Inc. - basic	$ 26,661	$ (8,520)	$ (15,189)
Add: Dividends on Series A Preferred Stock	7,938	—	—
Add: Net income attributable to the noncontrolling interest, net of taxes	47,432	—	—
Net income (loss) attributable to common stockholders of Rosehill Resources Inc. - diluted	$ 82,031	$ (8,520)	$ (15,189)
Weighted average shares (denominator):			
Weighted average shares – basic	8,196	5,945	5,857
Add: Dilutive effects of Series A Preferred Stock	8,495	—	—
Add: Dilutive effects of Class B Common Stock	29,808	—	—
Weighted average shares – diluted	46,499	5,945	5,857
Basic income (loss) per share	$ 3.25	$ (1.43)	$ (2.59)
Diluted income (loss) per share	$ 1.76	$ (1.43)	$ (2.59)

For the year ended December 31, 2018, the Company excluded 25.6 million shares of Class A Common Stock issuable upon exercise of the Company's warrant and 1.0 million shares of Class A Common Stock issuable upon vesting under the Company's Long-Term Incentive Plan from the computation of diluted earnings per share because the effect of such events was anti-dilutive.

For the year ended December 31, 2017, the Company excluded29.8 million shares of Class A Common Stock issuable upon exchange of the Company's Class B Common Stock, 25.6 million shares of Class A Common Stock issuable upon exercise of the Company's warrants and 8.5 million shares of Class A Common Stock issuable upon conversion of the Company's Series A Preferred Stock and 0.7 million shares of Class A Common Stock issuable upon vesting under the Company's Long-Term Incentive Plan from the computation of diluted earnings per share because the effect of such events was anti-dilutive.

Note 4 – Accounts Receivable

Accounts receivable is comprised of the following:

	December 31, 2018		December 31, 2017	
	Related Parties	Third-Parties	Related Parties	Third-Parties
	(In thousands)			
Revenue receivable (1)	$ —	$ 28,876	$ 13,601	$ 1,153
Realized derivative receivable	—	2,229	—	—
Transaction purchase price settlement	—	—	2,381	—
Joint interest billings	—	640	20	83
Other	78	515	20	291
Accounts receivable	$ 78	$ 32,260	$ 16,022	$ 1,527

(1) All of the revenue receivable from related parties is attributable to Gateway Gathering and Marketing. For a further discussion see Note 15 - *Related Party Transactions*

Note 5 – Derivative Instruments

Commodity derivatives. The Company enters into various derivative instruments primarily to mitigate a portion of the exposure to potentially adverse market changes in oil and natural gas commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. Oil and natural gas commodity derivative instruments are recorded on the consolidated balance sheet at fair value as either an asset or a liability with changes in fair value recognized currently in earnings. While commodity derivative instruments are utilized to manage the price risk attributable to expected oil and natural gas production, the Company's commodity derivative instruments are not designated as accounting hedges under the accounting guidance. The related cash flow impact of the commodity derivative activities is reflected as cash flows from operating activities unless they are determined to have a significant financing element at inception, in which case they are classified within financing activities. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps - The Company receives a fixed price for the contract and pays a floating market price to the counterparty.

Purchased put options - The Company purchases put options based on an index price from the counterparty by payment of a cash premium. If the index price is lower than the put's strike price at the time of settlement, the Company receives from the counterparty such difference between the index price and the purchased put strike price. If the market price settles above the put's strike price, no payment is due from either party.

Two-way costless collars - Arrangements that contain a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, the Company pays the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party and (3) if the index price is below the floor price, the Company will receive the difference between the floor price and the index price.

Three-way costless collars - Arrangements that contain a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date,

(1) if the index price is higher than the sold call strike price, the Company pays the counterparty the difference between the index price and sold call strike price,

(2)if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party,

(3) if the index price is between the sold put strike price and the purchased put strike price, the Company will receive the difference between the purchased put strike price and the index price and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price

Basis swaps - Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

Interest rate swaps - Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes.

Tema's interest rate swap was terminated by Tema on April 20, 2017. At the closing of the Transaction, selected crude oil options and natural gas options were designated to remain with Tema. In connection with the Transaction, certain crude oil swaps and natural gas swaps were transferred to the Company. Contracts with one counterparty were novated to the Company in July 2017.

Series B Preferred Stock bifurcated derivative - In the event of a change of control, the Company shall redeem in cash all of the outstanding shares of Series B Preferred Stock, excluding Series B PIK Shares, each as defined in Note 11 - *10% Series B Redeemable Preferred Stock*, for a price per share equal to the Base Return Amount as defined in Note 11 - *10% Series B Redeemable Preferred Stock*. The Company assessed the change of control feature and determined that the redemption of the outstanding shares of Series B Preferred Stock, excluding Series B PIK Shares, for a price per share equal to the Base Return Amount was a bifurcated derivative. See Note 11 - *10% Series B Redeemable Preferred Stock* for defined terms and more detail.

The following tables summarize the location and fair value amounts of all the Company's derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets:

	December 31, 2018		
	Gross Fair Value	**Gross Amounts Offset (1)**	**Net Recognized Fair Value**
	(In thousands)		
Assets			
Commodity derivatives - current	$ 46,972	$ (16,153)	$ 30,819
Commodity derivatives - non-current	88,008	(29,694)	58,314
Total assets	$ 134,980	$ (45,847)	$ 89,133
Liabilities			
Commodity derivatives - current	$ (16,153)	$ 16,153	$ —
Commodity derivatives - non-current	(29,694)	29,694	—
Series B Preferred Stock bifurcated derivative - non-current	(696)	—	(696)
Total liabilities	$ (46,543)	$ 45,847	$ (696)

(1) The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and liabilities.

	December 31, 2017		
	Gross Fair Value	Gross Amounts Offset (1)	Net Recognized Fair Value
	(In thousands)		
Assets			
Commodity derivatives - current	$ 1,079	$ (1,079)	$ —
Commodity derivatives - non-current	120	(120)	—
Total assets	$ 1,199	$ (1,199)	$ —
Liabilities			
Commodity derivatives - current	$ (11,851)	$ 1,079	$ (10,772)
Commodity derivatives - non-current	(7,503)	120	(7,383)
Series B Preferred Stock bifurcated derivative - non-current	(625)	—	(625)
Total liabilities	$ (19,979)	$ 1,199	$ (18,780)

(1) The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and liabilities.

As of December 31, 2018, the open commodity derivative positions with respect to future production were as follows:

	2019	2020	2021	2022
Commodity derivative swaps				
Oil:				
Notional volume (Bbls)	2,664,000	1,960,000	2,160,000	1,100,000
Weighted average fixed price ($/Bbl)	$ 53.59	$ 60.09	$ 61.21	$ 58.42
Natural gas:				
Notional volume (MMBtu)	2,220,000	1,500,000	1,200,000	1,200,000
Weighted average fixed price ($/MMbtu)	$ 2.88	$ 2.84	$ 2.85	$ 2.87
Ethane:				
Notional volume (Gallons)	12,444,138	—	—	—
Weighted average fixed price ($/Gallons)	$ 0.28	$ —	$ —	$ —
Propane:				
Notional volume (Gallons)	8,296,218	—	—	—
Weighted average fixed price ($/Gallons)	$ 0.79	$ —	$ —	$ —
Pentanes:				
Notional volume (Gallons)	2,765,700	—	—	—
Weighted average fixed price ($/Gallons)	$ 1.47	$ —	$ —	$ —
Commodity derivative two-way collars				
Oil:				
Notional volume (Bbls)	601,000	—	—	—
Weighted average ceiling price ($/Bbl)	$ 61.30	$ —	$ —	$ —
Weighted average floor price ($/Bbl)	$ 55.21	$ —	$ —	$ —
Commodity derivative three-way collars				
Oil:				
Notional volume (Bbls)	1,531,832	3,294,000	—	—
Weighted average ceiling price ($/Bbl)	$ 68.52	$ 70.29	$ —	$ —
Weighted average floor price ($/Bbl)	$ 57.62	$ 57.50	$ —	$ —
Weighted average sold put option price ($/Bbl)	$ 45.51	$ 47.50	$ —	$ —
Crude oil basis swaps				
Midland / Cushing:				
Notional volume (Bbls)	4,800,832	3,513,600	—	—
Weighted average fixed price ($/Bbl)	$ (4.93)	$ (1.43)	$ —	$ —
Natural gas basis swaps				
EP Permian:				
Notional volume (MMBtu)	1,781,472	2,096,160	—	—
Weighted average fixed price ($/MMBtu)	$ (1.03)	$ (1.03)	$ —	$ —

For the years ended December 31, 2018 and 2017, the effect of the derivative activity on the Company's Consolidated Statements of Operations was as follows:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Realized gain (loss) on derivatives			
Commodity derivative options	$ (83)	$ 172	$ 511
Commodity derivative swaps	(15,399)	45	(1,334)
Total	(15,482)	217	(823)
Interest rate swap	—	(143)	(785)
Total realized gain (loss) on derivatives	$ (15,482)	$ 74	$ (1,608)
Unrealized gain (loss) on derivatives			
Commodity derivative options	$ 28,965	$ 313	$ (1,508)
Commodity derivative swaps	79,121	(16,866)	(1,838)
Total	108,086	(16,553)	(3,346)
Interest rate swap	—	(226)	$ (3,346)
Series B Preferred Stock bifurcated derivative	(71)	—	324
Total unrealized gain (loss) on derivatives	$ 108,015	$ (16,779)	$ (3,022)

The gains and losses resulting from the cash settlement and mark-to-market of the commodity derivatives are included within "Gain (loss) on commodity derivative instruments, net" in the Consolidated Statements of Operations. The gains and losses resulting from the cash settlement and mark-to-market of the interest rate swap are included in "Interest expense, net" in the Consolidated Statements of Operations.

Note 6 – Fair Value Measurements

Financial Instruments

The financial instruments measured at fair value on a recurring basis consist of the following:

	December 31, 2018	December 31, 2017
	(In thousands)	
Derivative assets (liabilities)		
Derivative assets - current	$ 30,819	$ —
Derivative assets - non-current	58,314	—
Total derivative assets	89,133	—
Derivative liabilities - current	$ —	$ (10,772)
Derivative liabilities - non-current	(696)	(8,008)
Total derivative, net	$ 88,437	$ (18,780)

Derivative assets and liabilities primarily represent unsettled amounts related to commodity derivative positions, including swaps and options. Derivative liabilities also include the Series B Preferred Stock bifurcated derivative for the various redemption amounts that the Company could incur if a change of control event occurs. The Company utilizes Level 3 assumptions to estimate the probability of a change of control occurring and when that would occur as the timing impacts the Base Return Amount as defined in Note 11 - *10% Series B Redeemable Preferred Stock*. The change in fair value to the Series B Preferred Stock bifurcated derivative for the period is recorded in "Other income (expense), net" in the Consolidated Statements of Operations.

The tables below set forth by level within the fair value hierarchy represent the net components of the assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2018 and December 31, 2017. These net balances are intended solely to provide information on sources of inputs to fair value and proportions of fair value involving objective versus subjective valuations and do not represent either the actual credit exposure or net economic exposure.

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Derivative assets				
Commodity derivative assets - current	$ —	$ 30,819	$ —	$ 30,819
Commodity derivative assets - non-current	—	58,314	—	58,314
Total derivative assets	$ —	$ 89,133	$ —	$ 89,133
Derivative liabilities				
Series B Preferred Stock bifurcated derivative - non-current	$ —	$ —	$ (696)	$ (696)
Total derivative liabilities	$ —	$ —	$ (696)	$ (696)

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Derivative liabilities				
Commodity derivative liabilities - current	$ —	$ (10,772)	$ —	$ (10,772)
Commodity derivative liabilities - non-current	—	(7,383)	—	(7,383)
Series B Preferred Stock bifurcated derivative - non-current	—	—	(625)	(625)
Total derivative liabilities	$ —	$ (18,155)	$ (625)	$ (18,780)

The table below sets forth a summary of changes in the fair value of the Company’s level 3 liabilities for the year endedDecember 31, 2018.

Beginning Balance	$ 625
(Gains) losses reported in earnings	71
Ending Balance	$ 696

Financing Arrangements

The carrying amounts of the Company’s cash, cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate their fair values because of the short-term maturities and/or liquid nature of these assets and liabilities. The Company’s revolving credit facility carrying value is representative of its fair value because the interest rate changes monthly based on the current market of the stated rates in the agreement. As of December 31, 2018, the fair value of the 10% Senior Secured Second Lien Notes (the “Second Lien Notes”) was $95.2 million, which was determined using quoted prices for similar instruments, a Level 2 classification in the fair value hierarchy. Because the Second Lien Notes were negotiated on an arm’s length basis with reputable third-party lenders at prevailing market rates in December 2017, the Company determined the carrying value to be representative of the fair value at December 31, 2017.

Non-Financial Assets and Liabilities

Non-financial assets and liabilities that are initially measured at fair value are comprised of asset retirement obligations and the corresponding increase to the related long-lived asset and are not remeasured at fair value in subsequent periods. Such initial measurements are classified as Level 3 because certain significant unobservable inputs are utilized in their determination. The fair value of additions to asset retirement obligation liability and certain changes in the estimated fair value of the liability are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs to the valuation include (i) estimated plug and abandonment cost per well based on historical experience and information from third-parties; (ii) estimated remaining life per well; (iii) future inflation factors; and (iv) average credit-adjusted risk-free rate. These inputs require significant judgments and estimates by management at the time of the valuation and are the most sensitive and subject to change.

If the carrying amount of oil and natural gas properties exceeds the estimated undiscounted future cash flows, the carrying amount of the oil and natural gas properties will be adjusted to the fair value. The fair value of oil and natural gas properties is determined using valuation techniques consistent with the income and market approach. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, (i) recent sales prices of comparable properties; (ii) the present value of future cash flows, net of estimated operating and development costs using estimates of proved oil and natural gas reserves; (iii) future commodity prices; (iv) future production estimates; (v) anticipated capital expenditures; and (vi) various discount rates commensurate with the risk and current market conditions associated with the projected cash flows. These assumptions represent "Level 3" inputs.

Note 7 – Property and equipment

Property and equipment is comprised of the following:

	December 31, 2018	December 31, 2017
	(In thousands)	
Proved oil and natural gas properties	$ 777,558	$ 423,611
Unproved oil and natural gas properties	121,929	121,690
Land	1,575	406
Less: accumulated DD&A and impairment	(234,265)	(114,375)
Total oil and natural gas properties (successful efforts), net	666,797	431,332
Other property and equipment	6,059	4,345
Less: accumulated DD&A	(3,467)	(3,062)
Total other property and equipment	2,592	1,283
Total property and equipment, net	$ 669,389	$ 432,615

As the Company's exploration and development work progresses and the reserves on the Company's properties are proven, capitalized costs attributed to the properties and mineral interests are subject to DD&A. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated field. DD&A related to oil and natural gas properties was $140.4 million, $35.4 million and $24.4 million for the years ended December 31, 2018, 2017 and 2016, respectively. Depreciation and amortization expense related to other property and equipment was $0.7 million, $0.4 million, and $0.4 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Costs not subject to DD&A primarily include leasehold costs, broker and legal expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Leasehold costs are transferred into costs subject to depletion on an ongoing basis as these properties are evaluated and proved reserves are established. Additionally, costs associated with development wells in progress or awaiting completion at year-end are not subject to DD&A. These costs are transferred into costs subject to DD&A on an ongoing basis as these wells are completed and proved reserves are established or confirmed. Capitalized costs included in proved oil and natural gas properties not subject to DD&A totaled $87.1 million at December 31, 2018 and $57.2 million at December 31, 2017.

There were no impairment charges related to proved or unproved oil and natural gas properties recorded for the years ended December 31, 2018 and 2016. Impairment charges related to proved and unproved oil and natural gas properties was $1.1 million for the year ended December 31, 2017. There were no exploratory well costs pending determination of proved reserves for the years ended December 31, 2018 and 2017. There were no unsuccessful exploratory dry hole costs during the years ended December 31, 2018 and 2016. Unsuccessful exploratory dry hole costs were $0.2 million for the year ended December 31, 2017.

Acquisitions and Divestitures

White Wolf Acquisition

In December 2017, the Company acquired mineral rights and other associated assets and interests in the Southern Delaware Basin (the “White Wolf Acquisition”) for approximately $116.6 million, subject to customary purchase price adjustments, pursuant to a Purchase and Sale Agreement (the “PSA”) from certain sellers named therein (the “Sellers”). Subject to certain conditions under the PSA, until March 8, 2018, Rosehill Operating had the option to acquire additional oil and natural gas leases located within a certain designated area in the Delaware Basin (the “Designated Area”) from the Sellers. The option to purchase Additional Interest in the Designated Area expired on March 8, 2018 with the Company not acquiring any additional acreage. The Company incurred transaction fees of $2.9 million in connection with the White Wolf Acquisition, which were capitalized.

In addition to acquiring mineral rights, some of the leases contained producing wells and their associated personal property such as tank batteries and pumping units, which were holding those particular leases. The Company acquired the asset retirement obligation for those producing wells and associated personal property which totaled $1.6 million as of December 31, 2017. Total consideration paid in connection with the White Wolf Acquisition was $121.1 million. The Company accounted for the White Wolf Acquisition as an asset acquisition. The total consideration was recorded to unproved oil and natural gas properties and the liability acquired was recorded to asset retirement obligation based on relative fair value.

As of December 31, 2017, $4.0 million of the White Wolf Acquisition purchase price was in an escrow account. The PSA required that $4.0 million be placed in an escrow account to provide a non-exclusive source of funds to satisfy any liabilities incurred or sustained by the Company arising from any claims that the Sellers have indemnity obligations under the terms of the PSA. The funds were required to be escrowed until March 8, 2018, at which time any unused cash in the escrow account would be remitted to the Sellers. The Company did not use any of the escrowed funds and the full amount was released to the Seller in March 2018.

Other Acquisitions

In 2018, the Company paid approximately $15.3 million to acquire additional working interests, surface rights and additional royalty interests in our core areas throughout the Delaware Basin. In 2017, the Company purchased additional working interests in various operated wells and leasehold interests in Loving County, Texas for total consideration of $6.5 million.

Barnett Shale Divestiture

On November 2, 2017, the Company consummated the sale of Barnett Shale assets for a purchase price of approximately $7.1 million. After customary purchase price adjustments, the net purchase price was approximately $6.5 million, which resulted in gain on sale of $5.3 million. The divestiture of the Barnett Shale assets did not represent a strategic shift with a major effect on the Company’s operations and financial results, therefore, was not reported as a discontinued operation.

Note 8 – Asset Retirement Obligations

The following table summarized the changes in the Company's asset retirement obligation for the periods below:

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In thousands)	
Asset retirement obligations, beginning of year	$ 8,630	$ 5,431
Additional liabilities incurred	4,480	5,389
Dispositions	—	(2,380)
Accretion expense	638	317
Liabilities settled upon plugging and abandoning wells	(441)	(504)
Revision of estimates	217	377
Asset retirement obligations, end of year	13,524	8,630
Less: current portion of asset retirement obligations	—	108
Long-term asset retirement obligations	$ 13,524	$ 8,522

Note 9 – Accrued Liabilities and Other

Accrued liabilities and other is comprised of the following as of the respective dates:

	December 31, 2018	December 31, 2017
	(In thousands)	
Accrued payroll	$ 3,764	$ 2,352
Royalties payable	11,511	3,903
Accrued lease operating expense	3,992	2,230
Contingent liability - White Wolf Acquisition	—	4,005
Preferred Stock dividends payable	3,362	937
Accrued interest expense	925	639
Accrued production taxes	1,234	147
Accrued ad valorem taxes	1,066	—
Accrued debt issuance costs	631	—
Other	850	1,279
Total accrued liabilities and other	$ 27,335	$ 15,492

Note 10 – Long-term debt, net

The Company's long-term debt is comprised of the following:

	December 31, 2018	December 31, 2017
	(In thousands)	
Second Lien Notes	$ 100,000	$ 100,000
Revolving credit facility	194,000	—
Total debt	294,000	100,000
Debt issuance cost on Second Lien Notes, net	3,211	3,830
Discount on Second Lien Notes, net	2,491	2,971
Total debt issuance cost and discounts	5,702	6,801
Total long-term debt, net	$ 288,298	$ 93,199

Revolving Credit Facility

On March 28, 2018, the Company entered into an Amended and Restated Credit Agreement (the "Amended and Restated Credit Agreement") by and among the Company, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders. The borrowings under the Amended and Restated Credit Agreement bear interest at an adjusted base rate plus an applicable margin ranging from 1% to 2% or at an adjusted LIBO Rate plus an applicable margin ranging from 2% to 3%. As of December 31, 2018, the weighted average interest rate of outstanding borrowings under the Amended and Restated Credit Agreement was 5.308%. The Amended and Restated Credit Agreement amends and restates in its entirety the original credit agreement entered into on April 27, 2017 and amended on December 8, 2017. Pursuant to the Amended and Restated Credit Agreement, the lenders party thereto have agreed to provide the Company with a $500 million secured reserve-based revolving credit facility with an initial borrowing base of $150 million. The maturity date of the Amended and Restated Credit Agreement is August 31, 2022 and automatically extends to March 2023 upon the payment in full of the Second Lien Notes. The borrowing base is re-determined semi-annually, with the lenders and the Company each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The first redetermination date occurred on June 29, 2018, increasing the borrowing base from $150 million to $210 million and then it was increased to$220 million on December 5, 2018. Beginning in 2019, redeterminations will occur on April 1 and October 1. On March 28, 2019, the borrowing base was increased to $300 million.

The amounts outstanding under the Amended and Restated Credit Agreement are secured by first priority liens on substantially all of Rosehill Operating's oil and natural gas properties and associated assets and all of the stock of Rosehill Operating's material operating subsidiaries that are guarantors of the Amended and Restated Credit Agreement. If an event of default occurs under the Amended and Restated Credit Agreement, JPMorgan Chase Bank, N.A. will have the right to proceed against the pledged capital stock and take control of substantially all of Rosehill Operating and Rosehill Operating's material operating subsidiaries that are guarantors' assets. There are currently no guarantors under the Amended and Restated Credit Agreement.

The Amended and Restated Credit Agreement contains various affirmative and negative covenants. These covenants may limit Rosehill Operating's ability to, among other things: incur additional indebtedness; make loans to others; make investments; enter into mergers; make or declare dividends or distributions; enter into commodity hedges exceeding a specified percentage of Rosehill Operating's expected production; enter into interest rate hedges exceeding a specified percentage of Rosehill Operating's outstanding indebtedness; incur liens; sell assets; and engage in certain other transactions without the prior consent of JPMorgan Chase Bank, N.A. and/or the lenders.

The Amended and Restated Credit Agreement also requires Rosehill Operating to maintain the following financial ratios: (1) commencing on March 31, 2018, a current ratio, which is the ratio of consolidated current assets (including unused commitments under the Amended and Restated Credit Agreement, but excluding non-cash assets) to consolidated current liabilities (excluding non-cash obligations, current maturities under the Amended and Restated Credit Agreement and the Note Purchase Agreement (as defined below)), of not less than 1.0 to 1.0; (2) (x) commencing on March 31, 2018, a leverage ratio, which is the ratio of the sum of all of Rosehill Operating's Total Debt to Annualized EBITDAX (as such terms are defined in the Amended and Restated Credit Agreement) for the four fiscal quarters then ended, of not greater than 4.0 to 1.0 and (y) commencing on and after repayment in full of the Second Lien Notes (other than surviving contingent indemnification obligations) and the repayment or redemption in full of the Series B Preferred Stock, a leverage ratio, which is the ratio of the sum of all of Rosehill Operating's Net Debt to Annualized EBITDAX (as such terms are defined in the Amended and Restated Credit Agreement), of not greater than 4.0 to 1.0 and (3) commencing on March 31, 2018 for so long as the Series B Preferred Stock remains outstanding, a coverage ratio, which is the ratio of (i) EBITDAX (as defined in the Amended and Restated Credit Agreement) to (ii) the sum of (x) Interest Expense (as defined in the Amended and Restated Credit Agreement) plus (y) the aggregate amount of Restricted Payments (as defined in the Amended and Restated Credit Agreement) made in cash pursuant to Sections 9.04(a)(iv) and (v) of the Amended and Restated Credit Agreement during the preceding four fiscal quarters, of not less than 2.5 to 1.0. The Company was in compliance with the current ratio, leverage ratio and coverage ratio in the Amended and Restated Credit Agreement for the measurement period ended December 31, 2018.

Second Lien Notes

On December 8, 2017, Rosehill Operating issued and sold$100,000,000 in aggregate principal amount of 10.00% Senior Secured Second Lien Notes due January 31, 2023 to EIG Global Energy Partners, LLC ("EIG") under and pursuant to the terms of that certain Note Purchase Agreement, dated as of December 8, 2017 (as amended by the Limited Consent and First Amendment to Note Purchase Agreement, dated as of March 28, 2018, the "Note Purchase Agreement"), among Rosehill Operating, the Company, the holders of the Second Lien Notes party thereto (the "Holders") and U.S. Bank National Association, as agent and collateral agent on behalf of the Holders. The Second Lien Notes were issued and sold to the Holders in a private placement exempt from the registration requirements under the Securities Act of 1933, as amended (such issuance and sale, the "Notes Purchase").

Under the Note Purchase Agreement, Rosehill Operating may, at its option, redeem the Second Lien Notes in whole or in part, together with accrued and unpaid interest thereon, (i) at any time after December 8, 2019 but on or prior to December 8, 2020, at a redemption price equal to 103% of the principal amount of the Second Lien Notes being redeemed, (ii) at any time after December 8, 2020 but on or prior to December 8, 2021, at a redemption price equal to 101.5% of the principal amount of the Second Lien Notes being redeemed and (iii) at any time after December 8, 2021, at a redemption price equal to the principal amount of the Second Lien Notes being redeemed. On or prior to December 8, 2019, Rosehill Operating may, at its option, redeem the Second Lien Notes in whole or in part, together with accrued and unpaid interest thereon, at a redemption price equal to 103% of the principal amount of the Second Lien Notes being redeemed plus an additional make-whole premium set forth in the Note Purchase Agreement.

The Second Lien Notes may become subject to redemption under certain other circumstances, including upon the incurrence of non-permitted debt or, subject to various exceptions, reinvestments rights and prepayment or redemption rights with respect to other debt or equity of Rosehill Operating, upon an asset sale, hedge termination or casualty event. Rosehill Operating will be further required to make an offer to redeem the Second Lien Notes upon a Change in Control (as defined in the Note Purchase Agreement) at a redemption price equal to 101% of the principal amount being redeemed. Other than in connection with a change in control or casualty event, the redemption prices and make-whole premium described in the foregoing paragraph shall also apply, at such times and to the extent set forth therein, to any mandatory redemption of the Second Lien Notes or any acceleration of the Second Lien Notes prior to the stated maturity thereof upon the occurrence of an event of default.

The Note Purchase Agreement requires Rosehill Operating to maintain a leverage ratio, which is the ratio of the sum of all of Rosehill Operating's Total Debt to Annualized EBITDAX (as such terms are defined in the Note Purchase Agreement) for the four fiscal quarters then ended, of not greater than 4.00 to 1.00.

The Note Purchase Agreement contains various affirmative and negative covenants, events of default and other terms and provisions that are based largely on the Amended and Restated Credit Agreement, with a number of important modifications reflecting the second lien nature of the Second Lien Notes and certain other terms that were agreed to with the Holders. The negative covenants may limit Rosehill Operating's ability to, among other things, incur additional indebtedness (including under senior unsecured notes), make investments, make or declare dividends or distributions, redeem its preferred equity, acquire or dispose of oil and gas properties and other assets or engage in certain other transactions without the prior consent of the Holders, subject to various exceptions, qualifications and value thresholds. Rosehill Operating is also required to meet minimum commodity hedging levels based on its expected production on an ongoing basis.

The Company is subject to certain limited restrictions under the Note Purchase Agreement, including (without limitation) a negative pledge with respect to its equity interests in Rosehill Operating and a contingent obligation to guarantee the Second Lien Notes upon request by the Holders in the event that the Company incurs debt obligations. The obligations of Rosehill Operating under the Note Purchase Agreement are secured on a second-lien basis by the same collateral that secures its first-lien obligations.

In connection with the Notes Purchase, Rosehill Operating has granted first-lien and second-lien security interests over additional collateral to meet the minimum mortgage requirements under the Note Purchase Agreement.

The Company was in compliance with the financial covenants in the Note Purchase Agreement for the measurement period ended December 31, 2018.

Tema Credit Agreement

In December 2012, Tema entered into a secured line of credit with a bank for $60.0 million (the "Tema Credit Agreement"), with an optional expansion to $75.0 million, subject to satisfactory credit underwriting. Borrowings under the Tema Credit Agreement bore interest at floating LIBOR plus 1.00% (the Applicable Margin), and was collateralized by the existing producing oil and natural gas properties. There was no principal amortization required until the expiration of the Tema Credit Agreement, when all outstanding amounts became due.

Upon the closing of the Transaction on April 27, 2017, the $55.0 million outstanding balance under the Tema Credit Agreement was assumed by Rosehill Operating and immediately paid off using proceeds from the issuance of preferred stock in the Transaction. Concurrent with the initial draw down of the Tema Credit Agreement, an interest rate swap was entered into with a bank to fix the interest rate of the Tema Credit Agreement. In anticipation of the closing of the Transaction on April 20, 2017, the interest rate swap was terminated.

Debt Maturities

The following are maturities of long-term debt for each of the next five years and thereafter (amounts in thousands):

2019	$	—
2020		—
2021		—
2022		194,000
2023		100,000
Total	$	294,000

Deferred Financing Costs and Debt Discount

The Company capitalizes discounts and certain direct costs associated with the issuance of debt and amortizes such costs over the lives of the respective debt instruments. The Company amortized debt issuance costs and discounts of $2.1 million, $0.3 million and $0.1 million for the years ended December 31, 2018, 2017 and 2016, respectively. The deferred financing costs related to the Amended and Restated Credit Agreement are classified in prepaid assets and the deferred financing costs and discounts related to the Second Lien Notes are netted against the long-term debt. The following table summarizes the Company's deferred financing costs and debt discounts:

	December 31, 2018	December 31, 2017
	(In thousands)	
Revolving credit facility		
Debt issuance costs	$ 2,368	$ 1,219
Accumulated amortization of debt issuance costs	(361)	(541)
Net deferred costs - Revolving credit facility	$ 2,007	$ 678
Second Lien Notes		
Debt discount	$ 3,000	$ 3,000
Accumulated amortization of debt discount	(509)	(29)
Debt issuance costs	3,868	3,868
Accumulated amortization of debt issuance costs	(657)	(38)
Net deferred costs - Second Lien Notes	$ 5,702	$ 6,801
Total deferred financing costs and debt discount, net	$ 7,709	$ 7,479

Note 11 – 10% Series B Redeemable Preferred Stock

On December 8, 2017, in connection with the acquisition of mineral rights, royalty interest and other associated assets in the Southern Delaware Basin (the “White Wolf Acquisition”), the Company entered into a Series B Redeemable Preferred Stock Purchase Agreement (the “Series B Preferred Stock Agreement”) to issue 150,000 shares of the Company’s 10.00% Series B Redeemable Preferred Stock, par value of $0.0001 per share (the “Series B Preferred Stock”), for an aggregate purchase price of $150.0 million, less transaction costs, advisory and up-front fees of approximately $10.0 million to certain private funds and accounts managed by EIG (collectively, the “Series B Preferred Stock Purchasers”). The Company has the option, subject to certain conditions, to sell from time to time up to an additional 50,000 shares of Series B Preferred Stock, in aggregate, to the Series B Preferred Stock Purchasers and their transferees for a purchase price of $1,000 per share of Series B Preferred Stock. Such option terminated on December 8, 2018.

Holders of the Series B Preferred Stock are entitled to receive, when, as and if declared by the Board of Directors of the Company (the “Board”), cumulative dividends in cash, at a rate of 10.00% per annum on the $1,000 liquidation preference per share of Series B Preferred Stock, payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year, commencing on January 15, 2018. With respect to dividends declared for any quarter ending on or prior to January 15, 2019, the Company may elect to pay as dividends additional shares of Series B Preferred Stock in kind (the “Series B PIK Shares”) in an amount up to 40% of that which would have been payable had the dividends been fully paid in cash.

Holders of the Series B Preferred Stock have no voting rights and have limited consent rights with respect to the taking of certain corporate actions by the Company. Upon the Company’s voluntary or involuntary liquidation, winding-up or dissolution, each holder of Series B Preferred Stock will be entitled to receive the Base Return Amount (as defined in the Series B Preferred Stock Agreement) plus accrued and unpaid dividends.

The shares of Series B Preferred Stock are redeemable by the Company at the election of the holders on or after December 8, 2023, and upon certain conditions and at any time at the Company’s option. As the holders of Series B Preferred Stock have an option to redeem the Series B Preferred Stock at a future date, the proceeds from the Series B Preferred Stock have been included in temporary, or “mezzanine” equity, between total liabilities and stockholders’ equity on the Consolidated Balance Sheets. The Series B Preferred Stock, while not currently redeemable at the option of the holders, are considered probable of becoming redeemable and therefore will be subsequently remeasured each reporting period by accreting the initial value to the estimated redemption date of December 8, 2023 when the Series B Preferred Stock is redeemable in whole or in part at the election of the holders of Series B Preferred Stock. The accretion is presented as a deemed dividend and recorded in mezzanine equity on the Consolidated Balance Sheets and within preferred dividends on the Consolidated Statements of Operations.

In addition to the 10.00% per annum cumulative dividend holders of the Series B Preferred Stock are entitled to receive, upon redemption of the Series B Preferred Stock, such holders are guaranteed a base return on the initial 150,000 shares purchased in an amount equal to (1)$1,250 per share of Series B Preferred Stock times the number of outstanding shares of Series B Preferred Stock if the Company redeems the shares prior to the first anniversary of the date of issuance of such share of Series B Preferred Stock; (2) $1,350 per share of Series B Preferred Stock times the number of outstanding shares of Series B Preferred Stock if the Company redeems the shares on or after the first anniversary and prior to the second anniversary of the date of issuance of such share of Series B Preferred Stock; and (3) on or after the second anniversary of the date of issuance of such share of Series B Preferred Stock, the greater of (x) $1,500 per share of Series B Preferred Stock and (y) an amount necessary to achieve a16% IRR (the “Base Return Amount”) with respect to such shares of Series B Preferred Stock. Since the Series B Preferred Stock can be redeemed by the holders on or after December 23, 2023 and management has no plans to redeem before that date, the Company has accrued a guaranteed return amount in order to achieve the 16% IRR.

In the event of a change of control, the Company shall redeem in cash all of the outstanding shares of Series B Preferred Stock, excluding Series B PIK Shares, for a price per share equal to the Base Return Amount and all Series B PIK Shares at the purchase price of $1,000 per share. The Company assessed the change of control feature and determined that the redemption of the outstanding shares of Series B Preferred Stock, excluding Series B PIK Shares, for a price per share equal to the Base Return Amount was an embedded derivative that requires bifurcation and shall be accounted for at fair value. The Company measured the derivative liability and recorded a discount of $0.6 million upon initial measurement.

The Company reflected the following in mezzanine equity for the Series B Preferred Stock as ofDecember 31, 2018:

	Series B Preferred Shares	Series B Preferred Stock	Guaranteed Return	Total
	(In thousands, except share data)			
Total Series B Preferred Stock at January 1, 2017	—	$ —	—	—
Issuance of Series B Preferred Stock	150,000	$ 150,000	$ —	$ 150,000
Discount - upfront fees	—	(4,000)	—	(4,000)
Discount - transaction costs	—	(6,017)	—	(6,017)
Discount - bifurcated derivative	—	(625)	—	(625)
Net Proceeds	150,000	139,358	—	139,358
Return (16% IRR)	—	—	2,273	2,273
Dividends declared and payable in cash	—	—	(937)	(937)
Dividends declared and paid-in-kind	626	626	(626)	—
Accretion of Discount - deemed dividend	—	174	—	174
Total Series B Preferred Stock at December 31, 2017	150,626	140,158	710	140,868
Discount - transaction costs	—	(20)	—	(20)
Return (16% IRR)	—	—	22,092	22,092
Dividends declared and paid or payable in cash	—	—	(9,174)	(9,174)
Dividends declared and paid-in-kind	6,120	6,120	(6,120)	—
Accretion of discount - deemed dividend	—	1,345	—	1,345
Total Series B Preferred Stock at December 31, 2018	156,746	$ 147,603	$ 7,508	$ 155,111

For the first quarter, second quarter, third quarter, and fourth quarter of 2018, dividends per share on the Company’s Series B Preferred Stock was $24.66, $24.93, $25.21 and $25.21, respectively. For each quarter in 2018, the dividends on the Company’s Series B Preferred Stock were paid60% in cash and 40% paid-in-kind.

Note 12 – Income Taxes

In 2017, the Company became the sole managing member of Rosehill Operating, the Company's accounting predecessor. Rosehill Operating is a limited liability company that is treated as a partnership for U.S. federal income tax purposes and is not subject to U.S. federal income tax. Any taxable income or loss generated by Rosehill Operating is passed through to and included in the taxable income or loss of its members, including the Company. The Company is a C corporation and is subject to U.S. federal income tax and state and local income taxes.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation through Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). The provisions of the Tax Act that impact the Company include, but are not limited to, (1) reducing the U.S. federal corporate income tax rate from 35% to 21%; (2) eliminating the corporate alternative minimum tax ("AMT"); (3) allowing businesses to immediately expense the cost of new investments in certain qualified depreciable assets acquired after September 27, 2017 (with a phase-down of such expensing starting in 2023), (4) reducing the maximum deduction for net operating loss ("NOL") carryforwards generated in tax years beginning after December 31, 2017, to 80% of a taxpayer's taxable income and (5) imposing additional limits on future deductibility of interest expense and certain executive compensation. In conjunction with the Tax Act, the SEC staff issued Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (SAB 118), which provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC 740. In accordance with SAB 118, a company must reflect the income tax effects of those aspects of the Act for which the accounting under ASC 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. If a company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply ASC 740 on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the Tax Act. The Company booked no provisional amounts as of December 31, 2017 with respect to the Tax Act and no further adjustments were required during 2018. The SAB 118 period expired and our accounting is complete. We have calculated the impact of the Tax Act in our income tax provision in accordance with our understanding of the Tax Act and guidance available as of the date of this filing. As a result of the Tax Act, further clarifications and new regulations to the Tax Act continue to be issued at times. The Company will continue to monitor these new regulations and analyze their applicability and impact on the Company.

The Company remeasured its deferred tax assets and liabilities at December 31, 2017 using the lower 21% rate, resulting in a decrease in net deferred tax assets and its valuation allowance. Aside from the reduction to the U.S. federal corporate income tax rate, the Tax Act is not expected to have a significant current impact to the Company. The ultimate impact of the Tax Act may differ from the Company's estimates due to changes in interpretations or assumptions, as well as additional regulatory guidance that may be issued.

The components of income tax expense were as follows for the periods indicated:

	Year Ended December 31,		
	2018	**2017**	**2016**
	(In thousands)		
Current:			
State	5	—	148
	5	—	148
Deferred:			
Federal	15,687	1,537	—
State	2,470	153	—
	18,157	1,690	—
Income tax expense	$ 18,162	$ 1,690	$ 148

The Company's effective tax rate was 13.3%, 16.5% and 1.0% for the years ended December 31, 2018, 2017 and 2016, respectively. The effective tax rate differs from the enacted statutory rate of 21% for the years ended December 31, 2018 and 35% for the year ended December 31, 2017 and 2016 primarily due to the allocation of profits and losses to Rosehill and the noncontrolling interest holder in accordance with the LLC Agreement and the impact of state income taxes.

The following reconciles the income tax expense included in the consolidated statements of operations with the income tax expense that would result from the application of the statutory federal tax rate:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Income (Loss) before income taxes	$ 136,124	$ (10,258)	$ (15,041)
Income tax expense (benefit) at federal statutory rate	28,586	(3,590)	(5,264)
Net (income) loss prior to transaction	—	(1,545)	5,264
Net (income) loss before income taxes attributable to noncontrolling interest	(12,757)	6,584	—
State income taxes, net of federal benefit	2,323	153	148
Nondeductible expenses	—	88	—
Effect of change in federal statutory rate	—	1,941	—
Change in valuation allowance	—	(1,941)	—
Other	$ 10	$ —	$ —
Income tax expense	$ 18,162	$ 1,690	$ 148

The components of the Company's deferred tax balances were as follows for the periods indicated

	December 31,	
	2018	2017
	(In thousands)	
Deferred tax assets:		
Deferred stock-based compensation	—	232
Net operating loss carryforward	8,857	4,350
Other	16	30
Total deferred tax assets	8,873	4,612
Less: Valuation allowance	—	(2,912)
Net deferred tax assets	$ 8,873	$ 1,700
Deferred tax liabilities:		
Investment in Rosehill Operating	(15,042)	(1,700)
State deferred tax liability	(3,109)	(153)
Total deferred tax liabilities	(18,151)	(1,853)
Net deferred tax liabilities	$ (9,278)	$ (153)

As of December 31, 2018, the Company had approximately $38.1 million of U.S. federal net operating loss carryovers, which will begin to expire in2035. The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred tax assets, including NOL carry forwards. A valuation allowance for deferred tax assets is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. As of December 31, 2018, we have no valuation allowance because the Company thinks it is more likely than not that it's deferred tax assets will be realized prior to their expiration. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends and its outlook for future years.

Upon closing the Transaction, the Company acquired a portion of the Rosehill Operating Common Units and a deferred tax asset was recorded relating to the outside basis difference of its investment in Rosehill Operating for $5.7 million with an offsetting effect recorded in additional paid in capital. Due to uncertainties relating to the realization of the deferred tax asset at the time of the Transaction, the Company recorded a full valuation allowance with an offsetting effect recorded in additional paid in capital. Subsequent to the Transaction, the recognition of tax benefits resulted in a full reduction of the valuation allowance, with an offsetting effect recorded in additional paid in capital. Section 382 of the Internal Revenue Code of 1986, as amended ("IRC"), addresses company ownership changes and specifically limits the utilization of tax benefits generated prior to the Transaction following an ownership change. Upon closing of the Transaction, the Company believes it experienced an ownership change within the meaning of IRC Section 382 and recorded a valuation allowance of $0.2 million and an offsetting effect in additional paid in capital to fully offset these tax benefits.

The Company is subject to the following material taxing jurisdictions: the United States, Texas and New Mexico. As of December 31, 2018, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes and state income taxes for tax years 2016 through 2018.

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained upon examination. Therefore, as of December 31, 2018, the Company had not established any reserves for, nor recorded any unrecognized benefits related to, uncertain tax positions. The Company's policy is to recognize interest and penalties related to uncertain tax positions in income tax expense.

Tax Receivable Agreement

In connection with the Transaction, the Company entered into a tax receivable agreement ("Tax Receivable Agreement") with the noncontrolling interest holder, Tema. The Tax Receivable Agreement provides that the Company will pay to Tema 90% of the net cash savings, if any, in U.S. federal, state and local income tax that the Company realizes (or is deemed to realize in certain circumstances) in periods beginning with and after the closing of the Transaction as a result of the following: (i) any tax basis increases in the assets of Rosehill Operating resulting from the distribution to Tema of the Cash Consideration, the shares of Class B Common Stock and the Tema warrants, all in connection with the Transaction, and resulting from the assumption of Tema liabilities in connection with the Transaction, (ii) the tax basis increases in the assets of Rosehill Operating resulting from a redemption by Rosehill Operating with respect to Tema and (iii) imputed interest deemed to be paid by the Company as a result of, and additional tax basis arising from, payments it makes under the Tax Receivable Agreement.

The estimation of liability under the Tax Receivable Agreement is by its nature imprecise and subject to significant assumptions regarding the amount and timing of future taxable income. The Company is not obligated to make any payments under the Tax Receivable Agreement until the tax benefits associated with the transaction that gave rise to the payment are realized. Amounts payable under the Tax Receivable Agreement are contingent upon, among other things, (i) generation of future taxable income over the term of the Tax Receivable Agreement and (ii) future changes in tax laws. If the Company does not generate sufficient taxable income in the aggregate over the term of the Tax Receivable Agreement to utilize the tax benefits, then the Company would not be required to make the related Tax Receivable Agreement payment. As of December 31, 2018, the Company recognized a Tax Receivable Agreement liability of approximately $3.5 million after concluding that it was probable that we would have sufficient future taxable income to utilize the related tax benefits.

If and when Tema exercises its right to cause the Company to redeem all or a portion of its Rosehill Operating Common Units, a liability under the Tax Receivable Agreement relating to such redemption will be recorded. The amount of liability will be based on 90% of the estimated future cash tax savings that the Company will realize as a result of increases in the basis of Rosehill Operating's assets attributed to the Company resulting from such redemption. The amount of the increase in asset basis, the related estimated cash tax savings and the attendant Tax Receivable Agreement liability will depend, in part, on the price of the Class A Common Stock at the time of the relevant redemption. Due to the uncertainty surrounding the amount and timing of future redemptions of Rosehill Operating Common Units by Tema, the Company does not believe it is appropriate to record additional Tax Receivable Agreement liability until such time that Rosehill Operating Common Units are redeemed for shares of Class A Common Stock or cash.

Note 13 – Stockholders' Equity

The following description summarizes the material terms and provisions of the securities that the Company has authorized. Prior to the Transaction, KLRE was a shell company with no operations, formed as a vehicle to effect a business combination with one or more operating businesses. After the closing of the Transaction, the Company became a holding company whose sole material asset is its interest in Rosehill Operating. The following table summarizes the changes in the outstanding preferred stock, common stock and Class A common warrants exercisable for shares of Class A Common Stock through the date of the Transaction.

	Series A Preferred Stock	Class A Common Stock	Class B Common Stock	Class F Common Stock	Total Shares of Common Stock	Class A Common Stock Warrants
Issued at formation	—	588,276	—	4,312,500	4,900,776	588,276
Issued at IPO	—	7,597,044	—	—	7,597,044	7,597,044
Issued in connection with private placement	—	—	—	—	—	8,408,838
Forfeitures/Cancellation of founder shares	—	—	—	(2,266,170)	(2,266,170)	—
Conversion of founder shares	—	3,475,665	—	(2,046,330)	1,429,335	—
Redemption of Class A shares	—	(5,804,404)	—	—	(5,804,404)	—
Issued to Tema in connection with the Transaction	—	—	29,807,692	—	29,807,692	4,000,000
Preferred stock and warrants issued to PIPE Investors	75,000	—	—	—	—	5,000,000
Preferred stock issued to Sponsor and Rosemore Holdings, Inc.	20,000	—	—	—	—	—
Outstanding at the Transaction date	95,000	5,856,581	29,807,692	—	35,664,273	25,594,158

Class A Common Stock. Holders of the Company's Class A Common Stock are entitled to one vote for each share held on all matters to be voted on by the stockholders. Holders of the Class A Common Stock and holders of the Class B Common Stock voting together as a single class have the exclusive right to vote for the election of directors and on all other matters properly submitted to a vote of the stockholders. Additionally, the Sponsor and Tema agreed to restrictions on certain transfers of the Company's securities, which include, subject to certain exceptions, restrictions on the transfer of (i) 33% of their common stock through the first anniversary of the closing date of the Transaction, which restrictions lapsed on April 27, 2018, and (ii) 67% of their common stock through the second anniversary of the closing date, provided that sales of common stock above $18.00 per share will be permitted between the first and second anniversaries of the closing date of the Transaction. Further, in connection with underwritten offerings by the Sponsor and Tema, and subject to certain conditions, sales of common stock at a price reasonably expected to equal or exceed $18.00 per share and in any case equal to or in excess of $16.00 per share will be permitted.

On September 27, 2018, the Company entered into an underwriting agreement (the "Underwriting Agreement") with Citigroup Global Markets Inc., as representative of the several underwriters named therein (the "Underwriters"), for a public offering of 6,150,000 shares of common stock (the "Class A Common Stock Offering") at a public offering price of $6.10 per share ($5.795 per share net of underwriting discount and commissions). Pursuant to the Underwriting Agreement, the Company granted the Underwriters a 30-day option to purchase up to an additional 922,500 shares of Class A Common Stock.

On October 2, 2018, upon the closing of the Class A Common Stock Offering, the Company issued 6,150,000 shares of Class A Common Stock. The Company's net proceeds from the Class A Common Stock Offering, net of underwriting discounts and commissions and offering costs, was $34.5 million. On October 5, 2018, the Underwriters exercised their option to purchase an additional 840,744 shares of Class A Common Stock at the Underwriters' price of $5.795 per share. The Company received net proceeds of approximately $4.9 million for the shares of Class A Common Stock sold pursuant to the exercise of the Underwriters' option. The Company contributed all of the net proceeds from the Class A Common Stock Offering and the exercise of the Underwriters' option to Rosehill Operating in exchange for Rosehill Operating Common Units.

Class B Common Stock. Shares of Class B Common Stock may be issued only to Tema, their respective successors and assignees, as well as any permitted transferees of Tema. A holder of Class B Common Stock may transfer shares of Class B Common Stock to any transferee (other than the Company) only if such holder also simultaneously transfers an equal number of such holder's Rosehill Operating Common Units to such transferee in compliance with the LLC Agreement. Holders of the Company's Class B Common Stock will vote together as a single class with holders of the Company's Class A Common Stock on all matters properly submitted to a vote of the stockholders.

Holders of Class B Common Stock generally have the right to cause the Company to redeem all or a portion of their Rosehill Operating Common Units in exchange for shares of the Company's Class A Common Stock on a one-to-one basis or, at the Company's option, an equivalent amount of cash. The Company may, however, at its option, affect a direct exchange of cash or Class A Common Stock for such Rosehill Operating Common Units in lieu of such a redemption. Upon the future redemption or exchange of Rosehill Operating Common Units, a corresponding number of shares of Class B Common Stock will be canceled.

In the Transaction, the Company issued to Rosehill Operating 29,807,692 shares of its Class B Common Stock and 4,000,000 warrants exercisable for shares of its Class A Common Stock in exchange for 4,000,000 warrants exercisable for Rosehill Operating Common Units. Rosehill Operating immediately distributed the warrants and shares of Class B Common Stock to Tema.

Class F Common Stock. Upon the completion of the Transaction in April 2017, all of the outstanding Class F Common Stock (the "Founder Shares") were automatically converted into 3,475,665 shares of Class A Common Stock in connection with the Transaction. As used herein, unless the context otherwise requires, the Founder Shares are deemed to include the shares of Class A Common Stock issued upon conversion of the Founder Shares and such converted shares continue to be subject to certain transfer restrictions.

8% Series A Cumulative Perpetual Convertible Preferred Stock. Each share of Series A Preferred Stock has a liquidation preference of $1,000 per share and is convertible, at the holder's option at any time, initially into 86.9565 shares of the Company's Class A Common Stock (which is equivalent to an initial conversion price of approximately $11.50 per share of Class A Common Stock), subject to specified adjustments and limitations as set forth in the Certificate of Designation of Series A Preferred Stock (the "Certificate of Designation"). Under certain circumstances, the Company will increase the conversion rate upon a "fundamental change" as described in the Certificate of Designation.

The Company contributed the net proceeds of $70.8 million from its issuance of 75,000 shares of Series A Preferred Stock and 5,000,000 warrants exercisable for shares of Class A Common Stock to Rosehill Operating. In connection with the issuance of the Series A Preferred Stock, the Sponsor transferred 476,540 shares of its Class A Common Stock to the PIPE Investors to consummate the Transaction. The net proceeds from the issuance of these shares of Series A Preferred Stock and warrants was attributed to the Series A Preferred Stock, warrants and Class A Common Stock contributed by the Sponsor to the PIPE Investors based on the relative fair value of those securities using, among other factors, the closing price of the Class A Common Stock and the closing price of the warrants on April 27, 2017.

Rosemore and the Sponsor backstopped redemptions by the public stockholders of the Company once 30% of the outstanding shares of Class A Common Stock were redeemed by purchasing 20,000 shares of Series A Preferred Stock for net proceeds of $20 million pursuant to a side letter entered into between Rosemore, the Sponsor and the Company. The Company contributed to Rosehill Operating the net proceeds from the issuance of 20,000 shares of Series A Preferred Stock to Rosemore Holdings, Inc. and the Sponsor.

Upon issuance of the Series A Preferred Stock in April 2017, the nondetachable conversion option embedded in the Series A Preferred Stock was evaluated pursuant to ASC 470-20 and the Company determined that a beneficial conversion feature existed as of the closing date of the Transaction. The beneficial conversion feature was recognized separately from the Series A Preferred Stock in the Company's consolidated financial statements. The Company recognized in additional paid-in-capital, with an offsetting reduction in the carrying amount of the Series A Preferred Stock, the value of the beneficial conversion feature at the commitment date of $6.7 million. Since the Company's Series A Preferred Stock is perpetual and has no stated maturity date and no restrictions on conversion, the value attributable to the nondetachable conversion option was recognized immediately as a non-cash deemed dividend on the date that the Series A Preferred Stock was issued. Future issuances of Series A Preferred Stock resulting from dividends paid-in-kind may, depending on the trading price per share of the Company's Class A Common Stock on the dividend date, contain a beneficial conversion option determined on the same basis as described above and, thus, result in additional non-cash deemed dividends which will reduce net income attributable to Rosehill Resources, Inc. common stockholders when such paid-in-kind shares of Series A Preferred Stock are granted.

The Company also ratably recognizes additional non-cash deemed dividends attributable to the Series A Preferred Stock discount which was created by the issuance of the warrants exercisable for shares of Class A Common Stock and the contribution of the Class A Common Stock, as the Series A Preferred Stock which was sold to the PIPE Investors is converted. Also, upon Series A Preferred Stock conversions, non-cash deemed dividends will be recognized and will reduce net income attributable to Rosehill Resources Inc. common stockholders.

The Company reflected the following in equity for the Series A Preferred Stock as ofDecember 31, 2018:

	December 31,	
	2018	2017
	(In thousands)	
Liquidation Preference	$ 101,669	$ 97,698
Discount	(17,038)	(17,038)
Series A Preferred Stock	$ 84,631	$ 80,660

The table below summarizes the Series A Preferred Stock dividends reflected in the Company's Consolidated Statements of Operations:

	Year Ended December 31,	
	2018	2017
	(In thousands)	
Series A Preferred Stock paid-in-kind	$ 3,971	$ 5,530
Series A Preferred Stock paid or payable in cash	3,967	38
Series A Preferred Stock dividends	7,938	5,568
Deemed dividend related to beneficial conversion feature	—	6,700
Deemed dividend related to conversion to Class A Common Stock	—	668
Series A Preferred Stock dividends and deemed dividends	$ 7,938	$ 12,936

For the first quarter, second quarter, third quarter, and fourth quarter of 2018, dividends per share on the Company's Series A Preferred Stock was $19.73, $19.95, $20.16 and $20.16, respectively. For each quarter in 2018, the dividends on the Company's Series A Preferred Stock were paid50% in cash and 50% paid-in-kind.

Warrants. Each of the Company's warrants entitles the registered holder to purchase one share of the Company's Class A Common Stock at a price of$11.50 per share, subject to adjustment pursuant to the terms of the warrant agreement. The warrants have a five-year term which commenced on April 27, 2017, upon the completion of the Transaction, and will expire on April 27, 2022. The Company may call the warrants for redemption if the reported last sale price of the Class A Common Stock equals or exceeds $21.00 per share for any 20 trading days within a 30-trading day period ending on the third trading day prior to the date the Company sends the notice of redemption to the warrant holders.

There were 588,276 warrants issued in connection with the formation of the Company and7,597,044 public warrants (the "Public Warrants") issued in connection with KLRE's initial public offering. Additionally, there were 8,408,838 warrants issued to the Sponsor and EarlyBirdCapital Inc. pursuant to a private placement (the "Private Placement Warrants") in connection with the Company's initial public offering. The Private Placement Warrants are not redeemable by the Company and are exercisable on a cashless basis so long as they are held by the initial holders or their permitted transferees. Otherwise, the Private Placement Warrants have terms and provisions that are identical to those of the warrants described above. If the Private Placement Warrants are held by holders other than the initial holders or their permitted transferees, the Private Placement Warrants will be redeemable by the Company and exercisable by the holders on the same basis as the warrants described above.

In connection with the closing of the Transaction, the Company issued 5,000,000 warrants to the PIPE Investors and 4,000,000 warrants to Tema. These warrants were issued on the same terms, and are subject to the same rights and obligations, as described above.

As of December 31, 2018, there were 25,594,158 warrants exercisable for shares of Class A Common Stock outstanding at a price of $11.50. All warrants expire on April 27, 2022.

Noncontrolling Interest. Noncontrolling interest represents the membership interest held by holders other than the Company. On April 27, 2017, upon the closing of the Transaction, the noncontrolling interest in Rosehill Operating, held by Tema, was approximately 83.6%. The Company has consolidated the financial position and results of operations of Rosehill Operating and reflected the proportionate interest held by Tema as a noncontrolling interest. The noncontrolling interest will change when shares of Series A Preferred Stock are converted into shares of Class A Common Stock, when shares of Class A Common Stock are issued in connection with the Company's Long-Term Incentive Compensation plan and when Tema elects to exchange the Class B Common Stock received in connection with the transaction for shares of Class A Common Stock. At December 31, 2018, Tema held an approximate 68.4% noncontrolling interest in Rosehill Operating.

Note 14 - Stock-Based Compensation

Long-Term Incentive Plan

On May 22, 2018 at the Company's annual meeting of stockholders, the stockholders of the Company approved an amendment and restatement of the Rosehill Resources Inc. Long-Term Incentive Plan (as amended and restated, the "LTIP"). The purpose of the amendment and restatement was to revise the definition of "Change in Control" included in the LTIP and to remove certain tax provisions that are no longer applicable following the repeal of the "qualified performance-based compensation" exception to the Section 162(m) deduction limitation by the Tax Act. The LTIP permits the grant of a number of different types of equity, equity-based and cash awards to employees, directors and consultants, including grant options, SARs, restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, substitute awards, performance awards, or any combination of the foregoing, as determined by the Compensation Committee of the Board (the "Compensation Committee"), in its sole discretion. The purpose of the LTIP is to provide a means to attract and retain qualified service providers by affording such individuals a means to acquire and maintain stock ownership or awards, the value of which is tied to the performance of the Company. The LTIP also provides additional incentives and reward opportunities designed to strengthen such individuals' concern for the welfare of the Company and their desire to remain in its employ. At the plan's inception, 7,500,000 shares of Class A Common Stock were reserved for issuance under the LTIP.

As of December 31, 2018, the Company has granted restricted stock, restricted stock units and performance share units under the LTIP. Stock-based compensation expense for restricted stock and restricted stock units is recognized on a straight-line basis over the requisite service period for each separately vesting tranche of the award as if the award was, in substance, multiple awards. Stock-based compensation is included in general and administrative expense on the Company's Consolidated Statement of Operations and forfeitures are recognized as they occur. The stock-based compensation expense recognized was $6.5 million, $1.2 million and zero for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, 5,757,254 shares of Class A Common Stock remained available for issuance under the LTIP, subject to adjustment pursuant to the plan.

Restricted Stock

Restricted stock granted under the LTIP is issued on the grant date, but is restricted as to transferability until vesting. These restricted shares generally vest on the first anniversary of the date of grant. The following table sets forth the restricted stock transactions for the year ended December 31, 2018:

	Restricted Stock	Weighted-Average Grant Date Fair Value
Outstanding - December 31, 2017	105,666	$ 7.95
Granted	246,653	6.24
Vested	(105,666)	7.95
Forfeited	—	—
Outstanding - December 31, 2018	246,653	$ 6.24

As of December 31, 2018, there was $0.9 million of unrecognized compensation cost related to nonvested restricted stock which is expected to be recognized over a weighted-average period of 0.7 years.

Stock-Settled Time-Based Restricted Stock Units

Stock-settled time-based restricted stock units entitle the holder to receive one share of Class A Common Stock for each restricted stock unit when such restricted stock unit vests. These stock-settled time-based restricted stock units generally vest in three substantially equal installments on the first three anniversaries of the date of grant. The following table sets forth stock-settled time-based restricted stock unit transactions for the year ended December 31, 2018:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Nonvested - December 31, 2017	713,939	$ 9.88
Granted	549,150	6.62
Vested	(347,512)	9.44
Forfeited	(202,019)	7.96
Nonvested - December 31, 2018	713,558	$ 8.13

As of December 31, 2018, there was $4.0 million of unrecognized compensation cost related to nonvested stock-settled time-based restricted stock units which is expected to be recognized over a weighted-average period of 1.7 years.

Market Based Performance Share Units

On March 26, 2018, the Company granted a target number of 432,973 market based performance share units at a fair value of $8.99 per share to certain employees. The market based performance share units cliff vest on December 31, 2020 and will be settled in stock, provided that certain performance criteria are met. The performance criteria applicable to such awards is relative total shareholder return, which measures the Company's total shareholder return as compared to the total shareholder return of the peer group identified by the Compensation Committee. The Company recognizes compensation expense for the performance share units subject to market conditions regardless of whether it becomes probable that these conditions will be achieved or not and compensation expense is not reversed if vesting does not actually occur. The following table sets forth market based performance share unit transactions for the year ended December 31, 2018:

	Performance Restricted Stock Units	Weighted-Average Grant Date Fair Value
Nonvested - December 31, 2017	—	$ —
Granted	432,973	8.99
Vested	(46,649)	8.99
Forfeited	(101,909)	8.99
Nonvested - December 31, 2018	284,415	$ 8.99

The grant-date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Class A Common Stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The following assumptions were used to value the market based performance awards:

Expected volatility	89.5%
Risk-free interest rate	2.4%
Dividend yield	—%
Expected life (years)	2.77

As of December 31, 2018, there was $1.8 million of unrecognized compensation cost related to shares of market based performance restricted stock units which is expected to be recognized over a weighted average period of 2.0 years.

Cash-Settled Restricted Stock Units

During the year ended December 31, 2018, the Company granted 98,743 cash-settled restricted stock units to certain employees. Cash-settled restricted stock units entitle the holder to receive the cash equivalent of one share of Class A Common Stock for each restricted stock unit when such restricted stock unit vests. These cash-settled restricted stock units generally vest in three substantially equal installments on the first three anniversaries of the date of grant. Cash-settled restricted stock units are classified as liabilities and are remeasured at each reporting date until settled. The stock-based compensation expense for cash-settled restricted stock units is recognized on a straight-line basis over the requisite service period for each separately vesting tranche of the award as if the award was, in substance, multiple awards. The following table sets forth cash-settled restricted stock unit transactions for the year ended December 31, 2018:

	Cash-Settled Restricted Stock Units	Weighted-Average Grant Date Fair Value
Nonvested - December 31, 2017	—	$ —
Granted	98,743	6.62
Vested	—	—
Forfeited	(20,519)	6.60
Nonvested - December 31, 2018	78,224	$ 6.63

As of December 31, 2018, the Company had a liability for cash-settled restricted stock units of less than $0.1 million based on a closing price of $2.23 on December 31, 2018. As of December 31, 2018, there was $0.1 million of unrecognized compensation cost related to shares of cash-settled restricted stock units which is expected to be recognized over a weighted average period of 2.2 years.

Retirement Benefits

The Company has not maintained, and does not currently maintain, a defined benefit pension plan or nonqualified deferred compensation plan. The Company currently maintains a retirement plan pursuant to which employees are permitted to contribute portions of their base compensation to a tax-qualified retirement account. The Company provides matching contributions equal to 100% of elective deferrals up to 3% of eligible compensation and 50% of elective deferrals from 3% to a maximum of 5% of eligible compensation, subject to the applicable contributions limits. Beginning on January 1, 2019, the Company changed its matching contributions to 100% of elective deferrals up to 6% of eligible compensation. Matching contributions are immediately fully vested. The Company's matching contributions under the plan totaled $0.3 million, $0.1 million and $0.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Note 15 – Transactions with Related Parties

The Company is not entitled to compensation for its services as managing member of Rosehill Operating. The Company is entitled to reimbursement by Rosehill Operating for any costs, fees or expenses incurred on behalf of Rosehill Operating (including costs of securities offerings not borne directly by members, board of directors' compensation and meeting costs, cost of periodic reports to its stockholders, litigation costs and damages arising from litigation, accounting and legal costs); provided that the Company will not be reimbursed for any of its income tax obligations.

Rosemore. Rosemore provided employee benefits and other administrative services to Rosehill Operating. During the years ended December 31, 2017 and 2016, Rosemore incurred and Tema billed to Rosehill Operating approximately $9.6 million and $6.0 million, respectively, related to these services. Amounts incurred for employee benefits and other administrative services provided to Rosehill Operating by Rosemore prior to the Transaction were allocated to the Consolidated Statements of Operations as part of the carve-out financial statements – see "Cost Allocations" below. The costs incurred by Rosemore subsequent to the Transaction were billed to Rosehill Operating via the Transition Services Agreement (discussed under *Transaction Service Agreement* below) between Rosehill Operating and Tema. Rosemore did not provide these services to Rosehill Operating during the year ended December 31, 2018.

Transition Service Agreement. On April 27, 2017 in connection with the closing of the Transaction, the Company entered into a Transition Service Agreement ("TSA") with Tema to provide certain services to each other following the closing of the Transaction. Pursuant to the terms, the Company agreed to provide to Tema (i) operation services for the assets excluded from the Transaction, (ii) divestment assistance and (iii) office space to Gateway and Marketing ("Gateway"). Tema agreed to provide to the Company (i) human resources and benefits administration, (ii) information technology and telecommunications, (iii) general business insurance and (iv) legal services. The TSA terminated on October 27, 2018. Rosehill Operating did not incur significant costs related to providing services to Tema under the TSA for the year ended December 31, 2018. During the year ended December 31, 2017, the Company incurred and billed costs of $0.8 million related to services provided to Tema under the TSA. The amounts due from Tema at December 31, 2017 were less than $0.1 million.

Gateway Gathering and Marketing ("Gateway"). Gateway is a subsidiary of Rosemore. A portion of Rosehill Operating's oil production is sold to Gateway. For the years ended December 31, 2018, 2017 and 2016, revenues from production sold to Gateway were approximately $181.2 million, $61.3 million and $24.4 million, respectively. As of December 31, 2018, there was no revenue receivable due from Gateway. As of December 31, 2017, the revenue receivable due from Gateway was approximately $13.6 million.

Rosehill Operating has a Crude Oil Gathering Agreement and a Gas Gathering Agreement with Gateway for a portion of its production. The majority of the costs incurred under the Crude Oil Gathering Agreement were netted against the revenues received from Gateway due to Gateway being the purchaser of the oil production. Costs incurred for the year ended December 31, 2018 under the Crude Oil Gathering Agreement that was not netted against the revenues received from Gateway were $0.6 million, of which $0.3 million was payable due to Gateway as of December 31, 2018. Costs incurred under the Gas Gathering Agreement with Gateway for the years ended December 31, 2018, 2017 and 2016, were approximately $3.3 million, $1.1 million and $1.4 million, respectively. As of December 31, 2018, there was no payable due to Gateway related to the Gas Gathering Agreement. As of December 31, 2017, there was $0.2 million payable due to Gateway related to the Gas Gathering Agreement.

In 2018, Rosehill Operating entered into a Crude Oil Marketing Consulting Agreement with Gateway to, among other things, develop marketing strategies aimed at increasing realized prices from the sale of Rosehill Operating's production. Costs incurred in 2018 under the Crude Oil Marketing Consulting Agreement were $0.1 million, all of which was included in Accrued liabilities and other at December 31, 2018.

Certain consulting services were provided to Gateway. For the years ended December 31, 2017 and 2016, Gateway was invoiced amounts less than $0.1 million related to these services, which were recorded in general and administrative expenses in the accompanying Consolidated Statements of Operations. Certain other general and administrative services were also provided to Gateway, for which Gateway was invoiced approximately $0.1 million and $0.3 million for the years ended December 31, 2017 and December 31, 2016, respectively. As of December 31, 2017 and 2016, the receivable due from Gateway related to these services was less than $0.1 million and approximately $0.3 million, respectively.

Transaction expenses. Under the terms of the Transaction, the Company reimbursed Tema and Rosemore $1.6 million and $2.4 million, respectively, on April 27, 2017, for costs incurred in connection with the Transaction.

Distributions. The LLC Agreement requires Rosehill Operating to make a corresponding cash distribution to the Company at any time a dividend is to be paid by the Company to the holders of its Series A Preferred Stock and Series B Preferred Stock. The LLC Agreement allows for distributions to be made by Rosehill Operating to its members on a pro rata basis in accordance with the number of Rosehill Operating Common Units owned by each member out of funds legally available therefor. The Company expects Rosehill Operating may make distributions out of distributable cash periodically to the extent permitted by the Amended and Restated Credit Agreement and necessary to enable the Company to cover its operating expenses and other obligations, as well as to make dividend payments, if any, to the holders of its Class A Common Stock. In addition, the LLC Agreement generally requires Rosehill Operating to make (i) pro rata distributions (in accordance with the number of Rosehill Operating Common Units owned by each member) to its members, including the Company, in an amount at least sufficient to allow the Company to pay its taxes and satisfy its obligations under the Tax Receivable Agreement and (ii) tax advances, which will be repaid upon a redemption, in an amount sufficient to allow each of the members of Rosehill Operating to pay its respective taxes on such holder's allocable share of Rosehill Operating's taxable income after taking into account certain other distributions or payments received by the unitholder from Rosehill Operating or the Company.

Cost Allocations. For periods prior to the Transaction, Tema allocated certain overhead costs associated with general and administrative services, including insurance, professional fees, facilities, information services, human resources and other support departments related to Rosehill Operating. Also included in the cost allocations are costs associated with employees covered under Rosemore's defined benefit plan and long-term incentive compensation plan. Employees of Rosehill Operating no longer participate in either employee benefit plan. Overhead costs allocated were $1.5 million and $6.0 million for the year ended December 31, 2017 and 2016, respectively. There were no overhead costs allocated subsequent to the Transaction. Where costs incurred related to Rosehill Operating's assets in the periods prior to the Transaction could not be determined by specific identification, the costs were primarily allocated proportionately on a Boe basis. Management believes the allocations are a reasonable reflection of the utilization of services provided. However, the allocations may not fully reflect the expense that would have been incurred had Rosehill Operating's assets been a stand-alone company during the 2017 and 2016 periods presented.

The Transaction Purchase Price Settlement. The working capital adjustment in the Transaction was originally estimated to be$5.6 million and was contributed to Rosehill Operating by the Company upon closing the Transaction. The final working capital adjustment of $2.4 million due to the Company from Tema was reflected as a reduction to the preliminary purchase price as of December 31, 2017 and received by the Company in 2018.

KLR Sponsor. In October 2018, Rosehill Operating entered into a Water Purchase Agreement with Seawolf Water Resources, LP ("Seawolf"), an affiliate of KLR Sponsor, to purchase water from Seawolf's water wells for use in well completion operations. For the year ended December 31, 2018, Rosehill Operating incurred costs of $1.2 million, of which approximately $0.6 million was included in Accrued capital expenditures at December 31, 2018, related to the purchase of water from Seawolf's water wells.

In September 2017, the Company entered into an advisory agreement with KLR Group (the "Advisory Agreement"), an affiliate of KLR Sponsor, to pay a cash fee in an amount equal to 2.5% of the aggregate funds committed to finance the White Wolf Acquisition. The Company received a commitment of $200 million under the Series B Preferred Stock Agreement and $100 million under the Second Lien Notes to fund the White Wolf Acquisition. The Company paid an advisory fee of$7.5 million to KLR Group.

Note 16 – Commitments and Contingencies

Commitments

Leases and Other Commitments

The following is a schedule of the Company's future minimum lease payments with commitments that have initial or remaining lease terms in excess of one year as of December 31, 2018:

	2019	2020	2021	2022	2023	Thereafter	Total
	(In thousands)						
Operating lease obligations	$ 1,213	$ 1,202	$ 1,097	$ 557	$ —	$ —	$ 4,069
Capital lease obligations	34	3	—	—	—	—	37
Drilling commitments	6,525	—	—	—	—	—	6,525
Minimum volume commitment	1,692	1,692	1,526	380	—	—	5,290
Total	$ 9,464	$ 2,897	$ 2,623	$ 937	$ —	$ —	$ 15,921

Operating lease obligations. The Company leases office space in Houston, Texas and Midland, Texas. The Company recognized rent expense of$1.2 million, $1.0 million and $0.7 million for the years ended December 31, 2018, 2017 and 2016, respectively. The Company recognizes rent expense on a straight-line basis over the noncancelable lease term. The leases for office space in Houston, Texas and Midland, Texas expire in June 2022 and December 2020, respectively.

Capital lease obligations. The Company leases printers, scanners, and copiers for its office space. The Company's final payment on the leases will be in January 2020.

Rights of Securities Holders. The holders of the Founder Shares, the Series A Preferred Stock, the Private Placement Warrants and unregistered Class A Common Stock are entitled to registration rights pursuant to certain agreements of the Company. In May 2017, the Company filed a registration statement registering the Founder Shares, the Series A Preferred Stock (and any shares of Class A Common Stock issuable upon conversion of the Series A Preferred Stock), the Private Placement Warrants (and any shares of Class A Common Stock issuable upon the exercise of the Private Placement Warrants), the unregistered Class A Common Stock and the shares of Class A Common Stock issuable upon exercise of the outstanding Public Warrants. The registration statement has been effective since June 19, 2017.

Rosehill Operating Common Unit Redemption Right. The LLC Agreement provides Tema with a redemption right, which entitles Tema to cause Rosehill Operating to redeem, from time to time, all or a portion of its Rosehill Operating Common Units (and a corresponding number of shares of Class B Common Stock) for, at Rosehill Operating's option, newly issued shares of Class A Common Stock on a one-for-one basis or a cash payment equal to the average of the volume-weighted closing price of one share of Class A Common Stock for the twenty trading days prior to the date Tema delivers a notice of redemption for each Rosehill Operating Common Units redeemed (subject to customary adjustments, including for stock splits, stock dividends and reclassifications). In the event of a reclassification event (as defined in the LLC Agreement), the Company as managing member is required to ensure that each Rosehill Operating Common Unit (and a corresponding share of Class B Common Stock) is redeemable for the same amount and type of property, securities or cash that a share of Class A Common Stock becomes exchangeable for or converted into as a result of such reclassification event. Upon the exercise of the redemption right, Tema will surrender its Rosehill Operating Common Units (and a corresponding number of shares of Class B Common Stock) to Rosehill Operating and (i) Rosehill Operating shall cancel such Rosehill Operating Common Units and issue to the Company a number of Rosehill Operating Common Units equal to the number of surrendered Rosehill Operating Common Units and (ii) the Company shall cancel the surrendered shares of Class B Common Stock. The LLC Agreement requires that the Company contribute cash or shares of Class A Common Stock to Rosehill Operating in exchange for the issuance to the Company described in clause (i). Rosehill Operating will then distribute such cash or shares of Class A Common Stock to Tema to complete the redemption. Upon the exercise of the redemption right, the Company may, at its option, affect a direct exchange of cash or its Class A Common Stock for such Rosehill Operating Common Units in lieu of such a redemption.

Maintenance of One-to-One Ratios. The LLC Agreement includes provisions intended to ensure that the Company at all times maintains a one-to-one ratio between (a) (i) the number of outstanding shares of Class A Common Stock and (ii) the number of Rosehill Operating Common Units owned by the Company (subject to certain exceptions for certain rights to purchase equity securities of the Company under a "poison pill" or similar shareholder rights plan, if any, certain convertible or exchangeable securities issued under the Company's equity compensation plans and certain equity securities issued pursuant to the Company's equity compensation plans (other than a stock option plan) that are restricted or have not vested thereunder) and (b) (i) the number of other outstanding equity securities of the Company (including the Series A Preferred Stock and the warrants exercisable for shares of Class A Common Stock) and (ii) the number of corresponding outstanding equity securities of Rosehill Operating. These provisions are intended to result in Tema having a voting interest in the Company that is identical to Tema's economic interest in Rosehill Operating.

Contingencies

Legal. In the ordinary course of business, the Company is party to various legal actions, which arise primarily from its activities as operator of oil and natural gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on the Company's financial position or results of operation. There is no material litigation, arbitration or governmental proceeding currently pending against the Company or any members of its management team in their capacity as such.

Environmental Matters. Environmental assessments and remediation efforts are conducted at multiple locations, primarily previously owned or operated facilities. Environmental and clean-up costs are accrued when it is both probable that a liability has been incurred and the amount can be reasonably estimated. Accruals for losses from environmental remediation obligations generally are recorded no later than completion of the remediation feasibility study. Estimated costs, which are based upon experience and assessments, are recorded at undiscounted amounts without considering the impact of inflation and are adjusted periodically as additional or new information is available. Environmental assessments and remediation costs for the years ended December 31, 2018, 2017 and 2016 did not have a material adverse effect on the financial condition, results of operations and cash flows.

Supplemental Oil and Natural Gas Disclosures (Unaudited)

The Company's oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized Costs

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

	December 31,	
	2018	2017
	(In thousands)	
Oil and natural gas properties:		
Proved properties	777,558	423,611
Unproved properties	121,929	121,690
Land	1,575	406
Total oil and natural gas properties	901,062	545,707
Less: accumulated depreciation, depletion and amortization	(234,265)	(114,375)
Net Oil and natural gas properties	666,797	431,332

Costs Incurred for Oil and Natural Gas Producing Activities

The following table sets forth the costs incurred in the Company's oil and gas acquisition, exploration and development activities and includes costs whether capitalized or expensed as well as revisions and additions to the estimated future asset retirement obligation:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Property acquisition costs:			
Proved properties	$ 1,619	$ 6,500	$ 572
Unproved properties	14,993	121,207	—
Total property acquisition costs	16,612	127,707	572
Exploration costs	142,691	96,547	12,517
Development costs	220,981	126,563	11,143
Total costs incurred	$ 380,284	$ 350,817	$ 24,232

Results of Oil and Natural Gas Producing Activities

The following table sets forth results of operations for oil and natural gas producing activities for the following periods:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Revenues:			
Total revenues	301,875	76,236	34,645
Operating expenses:			
Lease operating expenses	39,010	10,881	4,800
Production taxes	14,506	3,535	1,541
Gathering and transportation	4,939	2,976	2,398
Depreciation, depletion, amortization and accretion	141,085	35,731	24,608
Impairment of oil and natural gas properties	—	1,061	—
Exploration costs	4,374	1,747	794
Income (loss) before income taxes	97,961	20,305	504
Income tax expense	20,572	1,690	148
Results of operations	77,389	18,615	356

Reserve Quantity Information

The following information represents estimates of the Company’s proved reserves as of December 31, 2018, which have been prepared and presented under SEC rules. These rules require SEC reporting companies to prepare their reserve estimates using specified reserve definitions and pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The pricing that was used for estimates of the Company’s reserves was based on an unweighted average 12-month WTI posted price per Bbl for oil and Henry Hub spot natural gas price per Mcf for natural gas for the years ended December 31, 2018, 2017 and 2016. The NGL price was based on 34% to 46%, depending on the property, of the unweighted average 12-month WTI posted price per Bbl for oil for the year ended December 31, 2018, an unweighted average 12-month Mont Belvieu posted price per Bbl for NGLs for the year ended December 31, 2017 and 27.5% of the unweighted average 12-month WTI posted price for the year ended December 31, 2016, as set forth in the following table:

	Year Ended December 31,		
	2018	2017	2016
Oil (per Bbl)	$ 65.56	$ 51.34	$ 42.75
Natural gas (per Mcf)	$ 3.10	$ 2.98	$ 2.49
Natural gas liquids (per Bbl)	$ 23.02	$ 31.82	$ 11.73

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement has limited and may continue to limit, the Company’s potential to record additional proved undeveloped reserves as it pursues its drilling program. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves with the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates.

Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following tables provide a roll forward of the total proved reserves for the years ended December 31, 2018, 2017 and 2016, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year:

	Crude Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	MBoe
Total proved reserves:				
Balance - December 31, 2015	5,652	13,899	1,994	9,963
Extensions and discoveries	3,537	5,694	993	5,479
Revisions of previous estimates	(1,221)	143	356	(841)
Purchases of reserves in place	—	—	—	—
Divestitures of reserves in place	—	—	—	—
Production	(612)	(2,381)	(358)	(1,367)
Balance - December 31, 2016	7,356	17,355	2,985	13,234
Extensions and discoveries	10,011	15,652	2,537	15,157
Revisions of previous estimates	1,970	10,915	1,347	5,136
Purchases of reserves in place	386	1,112	163	734
Divestitures of reserves in place	(16)	(3,009)	(482)	(1,000)
Production	(1,271)	(2,709)	(408)	(2,131)
Balance - December 31, 2017	18,436	39,316	6,142	31,131
Extensions and discoveries	18,131	21,087	3,781	25,427
Revisions of previous estimates	1,504	(10,589)	(1,240)	(1,501)
Purchases of reserves in place	—	—	—	—
Divestitures of reserves in place	—	—	—	—
Production	(4,913)	(5,231)	(908)	(6,693)
Balance - December 31, 2018	33,158	44,583	7,775	48,364
Proved developed reserves				
December 31, 2014	3,200	18,753	2,798	9,124
December 31, 2015	2,698	10,116	1,481	5,865
December 31, 2016	3,068	10,574	1,802	6,632
December 31, 2017	8,814	14,171	2,285	13,461
December 31, 2018	18,464	26,194	4,477	27,307
Proved undeveloped reserves				
December 31, 2014	3,089	8,869	1,501	6,068
December 31, 2015	2,954	3,783	513	4,098
December 31, 2016	4,288	6,781	1,183	6,601
December 31, 2017	9,622	25,145	3,857	17,670
December 31, 2018	14,694	18,388	3,298	21,057

Notable changes in proved reserves for the year ended December 31, 2018 included the following:

- *Extensions and discoveries.* During the period, 25,427 MBoe of proved reserves were added as a result of drilling activity primarily in the Wolfcamp and Bone Spring formations in Loving County within the Northern Delaware Basin.
- *Revisions of previous estimates.* During the period, 1,501 MBoe of proved reserves were deducted primarily due to PUD demotions partially offset by improved economics used in the reserve report.

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

- *Extensions and discoveries.* During the period, 15,157 MBoe of proved reserves were added as a result of drilling activity primarily in the Wolfcamp and Avalon formations in Loving County within the Northern Delaware Basin.
- *Revisions of previous estimates.* During the period, 5,137 MBoe of proved reserves were added primarily due to an increase in oil, natural gas and NGL prices and performance improvement.
- *Purchases of reserves in place.* During the period, 734 MBoe of purchased proved reserves relates to the purchase of additional working interest in various operated wells and leasehold interest in Loving County, Texas. See Note 7 - *Property and Equipment* for more discussion.
- *Divestitures of reserves in place.* During the period, 1,000 MBoe of divested proved reserves relates to the sale of the Barnett Shale assets. See Note7 - *Property and Equipment* for more discussion.

Notable changes in proved reserves for the year ended December 31, 2016 included the following:

- *Extensions and discoveries.* During the period, 5,479 MBoe of proved reserves were added as a result of drilling activity primarily in the Wolfcamp and Avalon formations in Loving County within the Northern Delaware Basin.
- *Revisions of previous estimates.* During the period, there was a decrease of 841 MBoe in proved reserves primarily due to lower oil, natural gas and NGL price partially offset by lower production costs and performance improvement.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2018, 2017 and 2016 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

The standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGLs reserves as of December 31, 2018, 2017 and 2016 is as follows:

	December 31,		
	2018	2017	2016
	(In thousands)		
Future cash inflows	2,154,058	1,125,928	360,651
Future production costs	(620,801)	(404,934)	(128,689)
Future development and net abandonment costs	(291,542)	(193,073)	(80,522)
Future net inflows before income tax expenses	1,241,715	527,921	151,440
Future income tax expenses (1)	(78,166)	(25,362)	(1,885)
Future net cash flows	1,163,549	502,559	149,555
10% discount to reflect timing of cash flows	(468,369)	(152,494)	(69,492)
Standardized measure of discounted future net cash flows	695,180	350,065	80,063

(1) Future income tax expense at December 31, 2018 and 2017 is attributable to Texas margin tax, the Company's ownership interest in Rosehill Operating and the 21% U.S. federal corporate income tax rate. Amounts at December 31, 2016 are attributable to Texas margin tax.

In the foregoing determination of future cash inflows, sales prices used for oil for December 31, 2018, 2017 and 2016 were estimated using the average first-day-of-the-month WTI prices for the twelve months included in each year. Sales prices used for natural gas for December 31, 2018, 2017 and 2016 were estimated using the average first-day-of-the-month Henry Hub prices for the twelve months included in each year. The sales prices used for NGLs for December 31, 2018 was based on 34% to 46%, depending on the property, of the average first-day-of-the-month WTI prices for oil for the twelve months included in the year, for December 31, 2017 was estimated using average first-day-of-the-month Mont Belvieu prices for the twelve months included in the year and for December 31, 2016 was based on 27.5% of the average first-day-of-the-month WTI prices for oil for the twelve months included in the year. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of its predecessor's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGLs reserves are as follows:

	December 31,		
	2018	2017	2016
	(In thousands)		
Standardized measure at the beginning of the period	350,065	80,063	86,269
Sales and transfers of oil and natural gas produced	(243,419)	(58,845)	(25,210)
Net change in prices and production costs	153,342	54,374	(21,705)
Net change due to purchases and sales of reserves in place	—	858	—
Net change due to extensions, discoveries, and improved recovery	361,696	222,590	33,586
Changes in estimated future development cost	10,244	(1,334)	16
Net change due to revisions in quantity estimates	46,250	13,080	(7,857)
Previously estimated development costs incurred during the year	57,853	26,710	3,953
Accretion of discount	36,787	8,122	8,720
Net change in income taxes	(29,574)	(16,649)	(225)
Changes in production rates, timing and other	(48,064)	21,096	2,516
Aggregate change	345,115	270,002	(6,206)
Standardized measure at the end of period	695,180	350,065	80,063

Supplemental Quarterly Financial Data (Unaudited)

The following presents selected unaudited annual financial data for 2018 and 2017:

	2018			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Revenues	$ 55,786	$ 80,527	$ 82,557	$ 83,005
Operating expenses	40,712	62,747	71,754	60,399
Operating income (loss)	15,074	17,780	10,803	22,606
Net income (loss)	(7,756)	8,664	(84,890)	201,944
Net income (loss) attributable to noncontrolling interest	(14,076)	(8,347)	(61,450)	143,799
Series A and Series B Preferred stock dividends	7,661	7,812	7,928	7,974
Net income (loss) attributable to Rosehill Resources Inc. common stockholders	$ (1,341)	$ 9,199	$ (31,368)	$ 50,171
Earnings (loss) per Basic common share	$ (0.22)	$ 1.43	$ (4.76)	$ 3.72
Earnings (loss) per Diluted common share	$ (0.22)	$ (0.32)	$ (4.76)	$ 2.35

	2017			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Revenues	$ 17,501	$ 14,665	$ 15,295	$ 28,775
Operating expenses	14,247	16,917	18,521	17,657
Operating income (loss)	3,254	(2,252)	(3,226)	11,118
Net income (loss)	4,414	(1,414)	(4,202)	(10,746)
Net income (loss) attributable to noncontrolling interest	—	(2,329)	(5,680)	(10,802)
Series A and Series B Preferred stock dividends	—	8,072	1,942	5,369
Net income (loss) attributable to Rosehill Resources Inc. common stockholders	$ 4,414	$ (7,157)	$ (464)	$ (5,313)
Earnings (loss) per Basic common share	$ 0.75	$ (1.22)	$ (0.08)	$ (0.87)
Earnings (loss) per Diluted common share	$ 0.75	$ (1.22)	$ (0.08)	$ (0.87)

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

None.

ITEM 9A. INTERNAL 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, including our 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 December 31, 2018. 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 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, the principal executive officer and principal financial officer concluded that the Company’s disclosure controls and procedures were effective as of December 31, 2018 at the reasonable assurance level.

Management's Annual Report on Internal Control Over Financial Reporting

Management, including the 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 the consolidated financial statements for external purposes in accordance with GAAP.

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.

Management assessed the effectiveness of our internal control over financial reporting as ofDecember 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, management, including the Chief Executive Officer and Chief Financial Officer, believes that our internal control over financial reporting was effective as of December 31, 2018.

Attestation Report of the Registered Public Accounting Firm

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal controls over financial reporting. We are not required to have, nor did we engage our independent audit firm to perform, an audit of the effectiveness of our internal controls over financial reporting for as long as we are an "emerging growth company" pursuant to the provisions of the JOBS Act.

Changes in Internal Control over Financial Reporting

In our annual report for the year ended December 31, 2017, we identified and disclosed material weaknesses related to the lack of sufficient qualified accounting personnel and inadequately designed accounting processes, which led to the incorrect application of generally accepted accounting principles, ineffective controls over accounting for non-routine and/or complex transactions, and ineffective controls over the financial statement close and reporting processes. To remediate the material weaknesses, we have recruited technical accounting and finance personnel and have made significant advancements to our processes and internal controls surrounding non-routine and complex arrangements to strengthen our financial reporting processes. Based on testing performed by management, we believe the implemented controls are operating effectively and the prior year material weaknesses have been remediated as of December 31, 2018. There were no other changes in our internal control over financial reporting during the year ended December 31, 2018 that 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

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

ITEM 11. EXECUTIVE AND DIRECTOR COMPENSATION

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements

The consolidated financial statements of the Company and reports of independent registered public accounting firms listed in Section 8 of this Annual Report on Form 10-K are filed as a part of this Annual Report on Form 10-K.

(2) Consolidated Financial Statement Schedules

All financial statement schedules are omitted because they are either not required, inapplicable or because the required information is presented in the Company's consolidated financial statements and related notes.

(3) Exhibits

The following is a complete list of exhibits filed as part of this Form 10-K. Exhibit number corresponds to the numbers in the Exhibit table of Item 601 of Regulation S-K.

Exhibit No.	Description
3.1	Second Amended and Restated Certificate of Incorporation of Rosehill Resources Inc. (1)
3.2	Certificate of Amendment of the Second Amended and Restated Certificate of Incorporation of Rosehill Resources Inc. (2)
3.3	Certificate of Designation for the Series A Preferred Stock of Rosehill Resources Inc. (1)
3.4	Amended and Restated Bylaws of Rosehill Resources Inc. (1)
3.5	Certificate of Designations for the Series B Preferred Stock of Rosehill Resources Inc. (3)
4.1	Specimen Unit Certificate (6)
4.2	Specimen Class A Common Stock Certificate (6)
4.3	Specimen Warrant Certificate (6)
4.4	Warrant Agreement, dated March 10, 2016, between the Company and Continental Stock Transfer & Trust Company (8)
4.5	Shareholders' and Registration Rights Agreement (9)
10.1	Amended and Restated Rosehill Resources Inc. Long-Term Incentive Plan. (5)
10.2	Global Amendment to Outstanding Awards under the Rosehill Resources Inc. Long-Term Incentive Plan, effective as of July 23, 2018 (4)
10.3	Offer Letter between Gary C. Hanna and Rosehill Operating Company, LLC, dated as of September 6, 2018. (5)
10.4	Restricted Stock Grant Notice (10)
23.1*	Consent of Independent Registered Public Accounting Firm, BDO USA, LLP
23.2*	Consent of Ryder Scott Company, LP.
23.3*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Ryder Scott Company, LP., Summary of Reserves at December 31, 2017 (7)
99.2	Ryder Scott Company, LP., Summary of Reserves at December 31, 2016 (7)
99.3*	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2018.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase.
101.PRE*	XBRL Taxonomy Extension Label Linkbase.
101.LAB*	XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith
** Furnished herewith

(1) Incorporated by reference to the Company's Form 8-K, filed with the Commission on May 3, 2017.
(2) Incorporated by reference to the Company's Registration Statement on Form S-1, filed with the Commission on May 11, 2018.
(3) Incorporated by reference to the Company's Form 8-K, filed with the Commission on December 14, 2017.
(4) Incorporated by reference to the Company's Form 8-K, filed with the Commission on July 27, 2018.
(5) Incorporated by reference to the Company's Form 8-K, filed with the Commission on September 12, 2018.
(6) Incorporated by reference to the Company's Amendment No. 1 to the Registration Statement (File no. 333-209041) on Form S-1/A, filed with the Commission on February 5, 2016.
(7) Incorporated by reference to the Company's Registration Statement (File no. 333-223041) on Form S-1, filed with the Commission on February 14, 2018.
(8) Incorporated by reference to the Company's Form 8-K, filed with the Commission on March 16, 2016.
(9) Incorporated by reference to the Company's Form 8-K, filed with the Commission on December 20, 2016.
(10) Incorporated by reference to the Company's Form 10-Q, filed with the Commission on November 9, 2018.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ROSEHILL RESOURCES INC.

March 28, 2019

By: /s/ R. Craig Owen
R. Craig Owen
Chief Financial Officer

Pursuant to the requirements of the Securities Act of 1934, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Gary C. Hanna Gary C. Hanna	Interim President and Chief Executive Officer (Principal Executive Officer)	March 28, 2019
/s/ R. Craig Owen R. Craig Owen	Chief Financial Officer (Principal Financial and Accounting Officer)	March 28, 2019
/s/ Frank Rosenberg Frank Rosenberg	Director	March 28, 2019
/s/ Edward Kovalik Edward Kovalik	Director	March 28, 2019
/s/ Harry Quarls Harry Quarls	Director	March 28, 2019
/s/ William Mayer William Mayer	Director	March 28, 2019
/s/ Francis Contino Francis Contino	Director	March 28, 2019
/s/ Paul J. Ebner Paul J. Ebner	Director	March 28, 2019

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

Rosehill Resources, Inc.
Houston, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-217683) and Form S-8 (No. 333-218023) of Rosehill Resources, Inc. of our report dated March 28, 2019, relating to the consolidated financial statements which appears in this Annual Report on Form 10-K.

/s/ BDO USA, LLP
Houston, Texas
March 28, 2019

Exhibit 23.2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the references to our firm in this Annual Report on Form 10-K for Rosehill Resources Inc., and to the use of information from, and the inclusion of, our reports, dated January 9, 2018, and January 17, 2017, with respect to the estimates of the proved reserves, future production and income as of December 31, 2017 and December 31, 2016, respectively, attributable to certain leasehold and royalty interests of Rosehill Resources Inc. (our "Reports") in this Annual Report on Form 10-K. We further consent to the reference to our firm under the heading “Experts” in this Annual Report on Form 10-K and to the incorporation by reference of our Reports and of references to us in Rosehill Resources Inc.'s Registration Statements on Form S-3 (No. 333-217683) and Form S-8 (No. 333-218023).

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
March 28, 2019

SUITE 800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

NETHERLAND, SEWELL
& ASSOCIATES, INC.

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm in this Annual Report on Form 10-K for Rosehill Resources Inc., and to the use of information from, and the inclusion of, our report, dated March 7,2019, with respect to the estimates of the proved reserves, future production and income as of December 31, 2018 attributable to certain leasehold and royalty interests of Rosehill Resources Inc. (our "Report") in this Annual Report on Form 10-K. We further consent to the reference to our firm under the heading "Experts" in this Annual Report on Form 10-K and to the incorporation by reference of our Report and of references to us in Rosehill Resources Inc.'s Registration Statements on Form S-3 (No. 333-217683) and Form S-8 (No. 333-218023).

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Danny D. Simmons

By: ______________________________

Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
March 28, 2019

Exhibit 31.1

CERTIFICATION
PURSUANT TO RULE 13a-14(a) AND 15d-14(a)
UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Gary C. Hanna, certify that:

1. I have reviewed this Annual Report on Form 10-K (this "report") of Rosehill Resources Inc. (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 officer 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 control 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 consolidated 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 officer 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: March 28, 2019

	/s/ Gary C. Hanna
Name:	Gary C. Hanna
Title:	Interim President and Chief Executive Officer (Principal Executive Officer)

Exhibit 31.2

CERTIFICATION
PURSUANT TO RULE 13a-14(a) AND 15d-14(a)
UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, R. Craig Owen, certify that:

1. I have reviewed this Annual Report on Form 10-K (this "report") of Rosehill Resources Inc. (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 officer 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 control 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 consolidated 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 officer 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: March 28, 2019

	/s/ R. Craig Owen
Name:	R. Craig Owen
Title:	Chief Financial Officer (Principal Financial and Accounting Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K for the period ended December 31, 2018 of Rosehill Resources Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacities and on the date indicated below, hereby certifies 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 operation of the Company.

Dated: March 28, 2019

	/s/ Gary C. Hanna
Name:	Gary C. Hanna
Title:	Interim President and Chief Executive Officer (Principal Executive Officer)

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K for the period ended December 31, 2018 of Rosehill Resources Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned, in the capacities and on the date indicated below, hereby certifies 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 operation of the Company.

Dated: March 28, 2019

	/s/ R. Craig Owen
Name:	R. Craig Owen
Title:	Chief Financial Officer (Principal Financial and Accounting Officer)

March 7, 2019

Mr. Brian K. Ayers
Rosehill Resources Inc.
16200 Park Row, Suite 300
Houston, Texas 77084

Dear Mr. Ayers:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2018, to the Rosehill Resources Inc. (Rosehill) interest in certain oil and gas properties located in New Mexico and Texas. 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 Rosehill. 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 Rosehill'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 Rosehill interest in these properties, as of December 31, 2018, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	17,813.8	4,075.3	23,059.2	813,418.1	540,512.9
Proved Developed Non-Producing	650.5	401.9	3,135.1	24,102.3	14,930.6
Proved Undeveloped	14,693.5	3,298.0	18,388.3	404,195.2	187,117.4
Total Proved	33,157.9	7,775.2	44,582.6	1,241,715.6	742,561.0

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) 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. As requested, probable and possible reserves that exist for these properties have not been included. 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 Rosehill's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Rosehill'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.

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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 and NGL 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. 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 $56.61 per barrel of oil, $23.02 per barrel of NGL, and $2.198 per MCF of gas.

Operating costs used in this report are based on operating expense records of Rosehill. These 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. Headquarters general and administrative overhead expenses of Rosehill are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Rosehill and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Rosehill'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 Rosehill 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 Rosehill receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical lease-level accounting statements.

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 Rosehill, 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, geologic maps, 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 and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for non-producing zones and undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. 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 Rosehill, 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 persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Richard B. Talley, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. Mike K. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

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

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

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

Date Signed: March 7, 2019

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: March 7, 2019

RBT:MSS

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

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

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

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

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

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

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

> Supplemental definitions from the 2018 Petroleum Resources Management System:
>
> Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
>
> Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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

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

of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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

hydrocarbons), and

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

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

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

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

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

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

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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

DEFINITIONS OF OIL AND GAS RESERVES

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

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

(23) Proved properties. Properties with proved reserves.

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

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

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

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

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

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

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

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

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

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

income tax expenses from future cash inflows.

DEFINITIONS OF OIL AND GAS RESERVES

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

> e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
> f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

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

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

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

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

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

> From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):
>
> Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.
>
> Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:
>
> - The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
> - The company's historical record at completing development of comparable long-term projects;
> - The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
> - The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
> - The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

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

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

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