HALCON RESOURCES CORP
Form 10-K
March 12, 2019

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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
Commission File Number: 001-35467

Halcón Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	**20-0700684**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

1000 Louisiana Street, Suite 1500, Houston, TX 77002
(Address of principal executive offices)

(832) 538-0300
(Registrant's telephone number)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.0001 per share	New York Stock Exchange

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

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

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 o No ý

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

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

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. ý

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 o	Accelerated filer ý	Non-accelerated filer o	Smaller reporting company o
			Emerging growth company o

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. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No ý

As of March 4, 2019, there were 160,261,776 shares outstanding of registrant's $.0001 par value common stock. Based upon the closing price for the registrant's common stock on the New York Stock Exchange as of June 30, 2018, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately $589.9 million.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13, and 14, is incorporated by reference to portions of the registrant's definitive proxy statement for its 2019 annual meeting of stockholders which will be filed no later than 120 days after December 31, 2018.

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Special note regarding forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, potential costs to be incurred, future cash flows and borrowings, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "objective," "believe," "predict," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. Readers should consider carefully the risks described under the "Risk Factors" section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, including, but not limited to, the following factors:

- volatility in commodity prices for oil, natural gas and natural gas liquids;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and develop our undeveloped acreage positions;
- our ability to replace our oil and natural gas reserves and production;
- the possibility that acquisitions may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits and may divert management's time and energy;
- we have historically had substantial indebtedness and we may incur more debt in the future;
- higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business;
- the presence or recoverability of estimated oil and natural gas reserves attributable to our properties and the actual future production rates and associated costs of producing those oil and natural gas reserves;
- our ability to successfully develop our large inventory of undeveloped acreage;
- our ability to retain key members of senior management, the board of directors, and key technical employees;
- senior management's ability to execute our plans to meet our goals;
- access to and availability of water and other treatment materials to carry out fracture stimulations in our resource play;
- access to adequate gathering systems, processing and treating facilities and transportation take-away capacity to move our production to marketing outlets to sell our production at market prices;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars;

contractual limitations that affect our management's discretion in managing our business, including covenants that, among other things, limit our ability to incur debt, make investments and pay cash dividends;

the potential for production decline rates for our wells to be greater than we expect;

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- our ability to successfully integrate acquired oil and natural gas businesses and operations;
- competition, including competition for acreage in our resource play;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulations);
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or acts of terrorism or sabotage;
- other economic, competitive, governmental, regulatory, legislative, including federal and state regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;
- our insurance coverage may not adequately cover all losses that we may sustain; and
- title to the properties in which we have an interest may be impaired by title defects.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Glossary of Oil and Natural Gas Terms

The definitions set forth below apply to the indicated terms as used in this report. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas differs significantly from the price for a barrel of oil. A barrel of NGLs also differs significantly in price from a barrel of oil.

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 installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed property. Property where wells have been drilled and production equipment has been installed.

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

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 exceed production expenses and taxes.

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

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

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.

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

Hydraulic fracturing. The injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production.

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

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

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

MMBoe. One million Boe.

MMBtu. One million Btu.

MMcf. One million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids, i.e. hydrocarbons removed as a liquid, such as ethane, propane and butane.

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

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 producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.

Proved developed reserves. Proved reserves that are expected to be recovered from existing wellbores, whether or not currently producing, without drilling additional wells. Production of such reserves may require a recompletion.

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Proved reserves. 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 estimation.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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

Reserve-to-production ratio or Reserve life. A ratio determined by dividing estimated existing reserves determined as of the stated measurement date by production from such reserves for the prior twelve month period.

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 reservoirs.

Spud. Commencement of actual drilling operations.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

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

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

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

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PART I

ITEM 1. BUSINESS

Overview

Unless the context otherwise requires, all references in this report to "Halcón," "our," "us," and "we" refer to Halcón Resources Corporation and its subsidiaries, as a common entity.

Certain prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, September 9, 2016.

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. During 2017, we acquired certain properties in the Delaware Basin and divested our assets located in the Williston Basin in North Dakota (the Williston Divestiture) and in the El Halcón area of East Texas (the El Halcón Divestiture). As a result, our properties and drilling activities are currently focused in the Delaware Basin, where we have an extensive drilling inventory that we believe offers attractive economics. The Williston Divestiture improved our liquidity and significantly reduced our debt, better enabling us to accelerate development of our Delaware Basin properties and execute our growth plans in the basin.

At December 31, 2018, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell) using the Securities and Exchange Commission (SEC) prices for crude oil and natural gas, which are based on the West Texas Intermediate (WTI) crude oil spot price of $65.56 per Bbl and Henry Hub natural gas spot price of $3.100 per MMBtu, were approximately 85.2 MMBoe, consisting of 50.7 MMBbls of oil, 17.1 MMBbls of natural gas liquids, and 104.7 Bcf of natural gas. Approximately 47% of our estimated proved reserves were classified as proved developed as of December 31, 2018. We maintain operational control of approximately 99% of our estimated proved reserves.

Our total operating revenues for 2018 were approximately $226.6 million compared to total operating revenues for 2017 of approximately $378.0 million. Full year 2018 production averaged 13,904 Boe/d compared to average daily production of 27,397 Boe/d for 2017. The decrease in total operating revenues and average daily production year over year was driven by our divestitures in 2017 and was partially mitigated by the production associated with our assets located in the Delaware Basin and our drilling activities since acquiring the assets. In 2018, we participated in the drilling of 31 gross (30 net) operated wells, none of which were dry holes.

Recent Developments

Sale of Water Infrastructure Assets

On December 20, 2018, we sold our water infrastructure assets located in the Delaware Basin (the Water Assets) to WaterBridge Resources LLC (the Purchaser) for an adjusted purchase price of $214.1 million in cash (the Water Infrastructure Divestiture) at closing. The effective date of the transaction was October 1, 2018. Additional incentive payments of up to $25.0 million per year for the next five years are available subject to our ability to meet certain annual incentive thresholds relating to the number of wells connected to the Water Assets per year. Our ability to achieve the incentive thresholds will be driven by, among other things, our development program which will consider future market conditions and is subject to change.

Upon closing, we dedicated all of the produced water from our oil and natural gas wells within our Monument Draw, Hackberry Draw and West Quito Draw operating areas to the Purchaser. There are no drilling or throughput commitments associated with the Water Infrastructure Divestiture. The

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Purchaser will receive a current market price, subject to annual adjustments for inflation, in exchange for the transportation, disposal and treatment of such produced water, and the Purchaser will receive a market price for the supply of freshwater and recycled produced water provided to us.

Acquisition of West Quito Draw Properties

On February 6, 2018, one of our wholly owned subsidiaries entered into a Purchase and Sale Agreement (the Shell PSA) with SWEPI LP (Shell), an affiliate of Shell Oil Company, pursuant to which we agreed to purchase acreage and related assets in the Delaware Basin located in Ward County, Texas (the West Quito Draw Properties) for a total adjusted purchase price of $198.5 million. The effective date of the acquisition was February 1, 2018, and we closed the transaction on April 4, 2018. We funded the cash consideration of the acquisition of the West Quito Draw Properties with the net proceeds from our issuance of the Additional 2025 Notes (defined below) and common stock, both of which are discussed below.

Issuance of Additional 2025 Notes

On February 15, 2018, we issued an additional $200.0 million aggregate principal amount of our 6.75% senior notes due 2025 at a price to the initial purchasers of 103.0% of par (the Additional 2025 Notes). The Additional 2025 Notes were sold pursuant to the exemption from registration under the Securities Act and applicable state securities laws, including Rule 144A and Regulation S under the Securities Act. The net proceeds from the sale of the Additional 2025 Notes were approximately $202.4 million after initial purchasers' premiums and deducting commissions and offering expenses. The proceeds were used to fund the cash consideration for the acquisition of the West Quito Draw Properties and for general corporate purposes, including funding our 2018 drilling program. These notes were issued under the Indenture, dated as of February 16, 2017, among us, certain of our subsidiaries and U.S. Bank National Association, as trustee, which governs our 6.75% senior notes due 2025 that were issued on February 16, 2017 (the 2025 Notes). The Additional 2025 Notes are treated as a single class with, and have the same terms as the 2025 Notes, except that the Additional 2025 Notes will initially be subject to transfer restrictions and have the benefit of certain registration rights and provisions for the payment of additional interest in the event of a breach with respect to such registration rights.

In connection with the issuance of the Additional 2025 Notes, on February 15, 2018, we, our subsidiary guarantors and J.P. Morgan Securities, LLC, on behalf of itself and the initial purchasers, entered into a Registration Rights Agreement, pursuant to which we and our subsidiary guarantors agreed to, among other things, use reasonable best efforts to file a registration statement under the Securities Act and complete an exchange offer for the Additional 2025 Notes within 180 days after closing. We filed such registration statement on March 20, 2018 and it was declared effective by the SEC on April 9, 2018. In addition, we completed the exchange offer for the Additional 2025 Notes on May 17, 2018.

Issuance of Common Stock

On February 9, 2018, we sold 9.2 million shares of common stock, par value $0.0001 per share, in a public offering at a price of $6.90 per share. The net proceeds to us from the offering were approximately $60.4 million, after deducting underwriters' discounts and offering expenses.

Senior Revolving Credit Facility

On February 28, 2019, the lenders party to our Senior Credit Agreement issued a consent (the Severance and Office Payments Consent) to us whereby Severance Payments and Office Payments (as defined in the Severance and Office Payments Consent) may exceed the maximum level allowed for adding back non-recurring expenses and charges in the definition of EBITDA (as defined in the Senior

Credit Agreement) when calculating the ratio of Consolidated Total Net Debt to EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarter ending March 31, 2019.

On February 15, 2019, we entered into the Seventh Amendment (the Seventh Amendment) to the Senior Credit Agreement which, among other things, provides for (i) the use of annualized financial data in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending March 31, 2019, June 30, 2019 and September 30, 2019 and (ii) amends the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA to be (a) 5.00 to 1.0 for the fiscal quarter ending March 31, 2019, (b) 4.75 to 1.0 for the fiscal quarter ending June 30, 2019, (c) 4.5 to 1.0 for the fiscal quarter ending September 30, 2019, (d) 4.25 to 1.0 for the fiscal quarter ending December 31, 2019, and (e) 4.0 to 1.0 for the fiscal quarter ending March 31, 2020 and any fiscal quarter thereafter.

On November 16, 2018, we entered into the Sixth Amendment (the Sixth Amendment) to the Senior Credit Agreement, which, among other things, provided for (i) provisions allowing for optional increases in the maximum Credit Amount (as defined in the Senior Credit Agreement) by us and the lenders party thereto. The Sixth Amendment also established the borrowing base at $350.0 million following the closing of the sale of the Water Assets; however, we and the lenders agreed to reduce the Aggregate Maximum Credit Amounts (as defined in the Senior Credit Agreement) to $275.0 million, thereby effectively limiting the amount available to borrow under the Senior Credit Agreement to $275.0 million.

On November 7, 2018, we entered into the Fifth Amendment (the Fifth Amendment) to the Senior Credit Agreement which, among other things, provided for (i) the use of annualized financial data in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending September 30, 2018, December 31, 2018, March 31, 2019, June 30, 2019 and September 30, 2019 and (ii) amended the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA of (a) 4.75 to 1.0 for the fiscal quarter ending September 30, 2018, (b) 4.25 to 1.0 for the fiscal quarter ending December 31, 2018 and (c) 4.0 to 1.0 for the fiscal quarter ending March 31, 2019 and any fiscal quarter thereafter.

On November 6, 2018, the lenders party to our Senior Credit Agreement issued a consent (the H2S Consent) to us whereby H2S Expenses (as defined in the H2S Consent) may exceed the maximum level allowed for adding back non-recurring expenses and charges in the definition of EBITDA (as defined in the Senior Credit Agreement) when calculating the ratio of Consolidated Total Net Debt to EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending September 30, 2018, December 31, 2018 and March 31, 2019.

During the year, we also periodically sought amendments to the covenants in the Senior Credit Agreement, including the financial covenants, where we anticipated difficulty in maintaining compliance. On July 12, 2018, we entered into the Fourth Amendment to the Senior Credit Agreement and on February 2, 2018, we entered into the Second Amendment to the Senior Credit Agreement. Refer to *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*, for a further discussion of these amendments.

Option Agreement to Acquire Monument Draw Assets (Ward and Winkler Counties, Texas)

On December 9, 2016, one of our wholly owned subsidiaries entered into an agreement with a private company, pursuant to which it acquired the rights to purchase up to 15,040 net acres in the Monument Draw area of the Delaware Basin, located in Ward and Winkler Counties, Texas (the Ward County Assets) prospective for the Wolfcamp and Bone Spring formations. The Ward County Assets are divided into two tracts (the Southern Tract and the Northern Tract) with separate options for each tract. Pursuant to the terms of the agreement (as amended), on June 15, 2017, we purchased the

Southern Tract for approximately $87.4 million and on January 9, 2018, we purchased the Northern Tract for approximately $108.2 million.

2019 Capital Budget

We expect to spend approximately $190 million to $210 million on drilling and completion capital expenditures during 2019. Overall, we currently plan to drill 17 gross operated wells during the year, complete 18 gross operated wells, bring 23 gross operated wells on production, and have five gross operated wells drilling over year-end 2019. Our 2019 drilling and completion budget currently contemplates running an average of two operated rigs in the Delaware Basin during the year and is subject to change. In addition, we expect to spend approximately $60 million to $80 million on infrastructure, seismic and other activities in 2019.

We expect to fund our budgeted 2019 capital expenditures with cash and cash equivalents on hand, cash flows from operations and borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to maintain adequate borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and fund infrastructure projects. In the event our cash flows are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may be required to curtail drilling, development, land acquisitions and other activities to reduce our capital spending.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominately upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves in an economical manner is critical to our long-term success.

Business Strategy

Our primary long-term objective is to increase stockholder value by cost-effectively increasing our production of oil, natural gas and natural gas liquids, adding to our proved reserves and growing our inventory of economic drilling locations. To accomplish this objective, we intend to execute the following business strategies:

Develop our Acreage Position to Grow Production and Reserves Efficiently. We are the operator for the majority of our acreage, which gives us control over the timing of capital expenditures, execution and costs. It also allows us to adjust our capital spending based on drilling results and the economic environment. As operator, we are also able to evaluate industry drilling results and implement improved operating practices which may enhance our initial production rates, ultimate recovery factors and rate of return on invested capital.

Manage Our Property Portfolio Actively. We continually evaluate our property base to identify and either divest, acquire or trade acreage to allow us to optimally execute on our plans to drill long-lateral operated wells (i.e. primarily 10,000 foot laterals). We may also divest less economic properties over time which will allow us to focus on a portfolio of core properties with the greatest economic potential to increase our proved reserves and production.

Selectively Grow Our Acreage Positions. We plan to selectively acquire high quality assets complementary to our core acreage and expand our drilling inventory. We will leverage our management team's geologic, engineering and financial expertise to selectively identify and execute on such acreage at attractive prices.

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Oil and Natural Gas Reserves

The proved reserves estimates reported herein for the years ended December 31, 2018, 2017 and 2016 have been independently evaluated by Netherland, Sewell, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland, Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland, Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland, Sewell reserves reports incorporated herein are Mr. Neil H. Little and Mr. Mike K. Norton. Mr. Little, a Licensed Professional Engineer in the State of Texas (No. 117966), has been practicing consulting petroleum engineering at Netherland, Sewell since 2011 and has over nine years of prior industry experience. He graduated from Rice University in 2002 with a Bachelor of Science Degree in Chemical Engineering and from University of Houston in 2007 with a Master of Business Administration Degree. Mr. Norton, a Licensed Professional Geoscientist in the State of Texas (No. 441), has been a practicing petroleum geoscience consultant at Netherland, Sewell since 1989 and has over ten years of prior industry experience. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Netherland, Sewell has reported to us that both 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; they are both proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our board of directors has established a reserves committee composed of independent directors with experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Senior Vice President of Corporate Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to our board of directors as to whether to approve the report prepared by our independent engineering firm. Ms. Tina Obut, our Senior Vice President of Corporate Reserves, is primarily responsible for overseeing the preparation of the annual reserve report by Netherland, Sewell. She graduated from Marietta College with a Bachelor of Science degree in Petroleum Engineering, received a Master of Science degree in Petroleum and Natural Gas Engineering from Penn State University and a Master of Business Administration degree from the University of Houston.

The reserves information in this Annual Report on Form 10-K represents only estimates. Reserve evaluation is a subjective process of estimating underground accumulations of 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 and judgment. As a result, estimates of different engineers may vary significantly. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell and other information about our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data* "*Supplemental Oil and Gas Information (Unaudited)*."

Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month for the 12-month period ended December 31, 2018. Average prices for the 12-month period were as follows: WTI crude oil spot price of $65.56 per Bbl, adjusted by lease or field for quality, transportation fees, and market differentials and a Henry Hub natural gas spot price of

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$3.100 per MMBtu, as adjusted by lease or field for energy content, transportation fees, and market differentials. All prices and costs associated with operating wells were held constant in accordance with SEC guidelines.

The following table presents certain proved reserve information as of December 31, 2018.

Proved Reserves (MBoe)[1]	
Developed	39,869
Undeveloped	45,343
Total	85,212

(1) *Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.*

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2018 and 2017. Shut-in wells currently not capable of production are excluded from the well information below.

	Years Ended December 31,			
	2018		**2017**	
	Gross	**Net**	**Gross**	**Net**
Oil	109	87.1	36	30.7
Natural Gas	13	9.5	2	1.7
Total	122	96.6	38	32.4

Oil and Natural Gas Production

During 2017, we divested our assets located in the Williston Basin in North Dakota and in the El Halcón area of East Texas, which represented substantially all of our proved reserves and production at the time, and we acquired certain properties in the Delaware Basin. As a consequence, our estimated proved reserves, oil and natural gas production and anticipated capital expenditures are currently focused entirely in this core area.

Core Resource Play Delaware Basin

We have working interests in approximately 56,900 net acres in the Delaware Basin as of December 31, 2018 in Pecos, Reeves, Ward and Winkler Counties, Texas. This core resource play is characterized by high oil and liquids-rich natural gas content in thick, continuous sections of source rock that can provide repeatable drilling opportunities and significant initial production rates. Our primary targets in this area are the Wolfcamp and Bone Spring formations. Our current capital budget contemplates running an average of two operated rigs in the Delaware Basin during 2019. As of December 31, 2018, we had approximately 104 operated wells producing in this area in addition to minor working interests in 19 non-operated wells. Our average daily net production from this area for the year ended December 31, 2018 was approximately 13,900 Boe/d. As of December 31, 2018, estimated proved reserves for the Delaware Basin were approximately 85.2 MMBoe, of which approximately 47% were classified as proved developed and approximately 53% as proved undeveloped.

Risk Management

We have designed a risk management policy for the use of derivative instruments to provide partial protection against certain risks relating to our ongoing business operations, such as commodity price

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declines, including price differentials between the NYMEX commodity price and the index price at the location where our production is sold. Derivative contracts are utilized to hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales of future oil and natural gas production. Our objective generally is to hedge 70-80% of our anticipated oil and natural gas production for the next 18 to 24 months. However, our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. Our hedge policies and objectives change as our operational profile changes and/or commodity prices. Our future performance is subject to commodity price risks and our future cash flows from operations may be subject to greater volatility than historically. We do not enter into derivative contracts for speculative trading purposes.

While there are many different types of derivatives available, we typically use costless collar, fixed-price swap and basis swap agreements to attempt to manage price risk more effectively. The costless collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All costless collar agreements provide for payments to counterparties if the settlement price under the agreement exceeds the ceiling and payments from the counterparties if the settlement price under the agreement is below the floor. The swap agreements call for payments to, or receipts from, counterparties depending on whether the index price of oil or natural gas for the period is greater or less than the fixed price established for the period contracted under the swap agreement. Basis swaps effectively lock in a price differential between regional prices (i.e. Midland) where the product is sold and the relevant pricing index under which the oil production is hedged (i.e. Cushing).

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. As of December 31, 2018, the Company did not post collateral under any of its derivative contracts as they are secured under the Company's Senior Credit Agreement or are uncollateralized trades. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* and Item 8. *Consolidated Financial Statements and Supplementary Data* Note 9*, "Derivative and Hedging Activities,"* for additional information.

Oil and Natural Gas Operations

Our principal properties consist of leasehold interests in developed and undeveloped oil and natural gas properties and the reserves associated with these properties. Generally, oil and natural gas leases remain in force as long as production in paying quantities is maintained. Leases on undeveloped oil and natural gas properties are typically for a primary term of three to five years within which we are generally required to develop the property or the lease will expire. In some cases, the primary term of leases on our undeveloped properties can be extended by option payments; the amount of any

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payments and time extended vary by lease. The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive[(1)]						
Dry						
Total Exploratory						
Extension Wells:						
Productive[(1)]	15	12.5	84	13.0	54	8.5
Dry						
Total Extension	15	12.5	84	13.0	54	8.5
Development Wells:						
Productive[(1)]	15	15.0	40	20.7	36	22.1
Dry						
Total Development	15	15.0	40	20.7	36	22.1
Total Wells:						
Productive[(1)]	30	27.5	124	33.7	90	30.6
Dry						
Total	30	27.5	124	33.7	90	30.6

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(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 extension or exploratory wells where there is no production history.*

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying provisions. The following table presents a summary of our acreage interests as of December 31, 2018:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
State	Gross	Net	Gross	Net	Gross	Net
Montana	280	66	1,353	562	1,633	628
North Dakota	3,830	694	34,045	13,945	37,875	14,639
Oklahoma			746	443	746	443
Texas	33,922	29,301	35,121	27,623	69,043	56,924

Total Acreage	38,032	30,061	71,265	42,573	109,297	72,634

The table below reflects the percentage of our total net undeveloped acreage as of December 31, 2018 that will expire each year if we do not establish production in paying quantities on the units in

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which such acreage is included or do not pay (to the extent we have the contractual right to pay) delay rentals or obtain other extensions to maintain the lease.

Year	Percentage Expiration
2019	4%
2020	9%
2021	7%
2022	25%
2023 & beyond	55%
	100%

For our proved undeveloped locations that are not scheduled to be drilled until after lease expiration, we continually review our near-term lease expirations to determine which lease extensions and renewals to actively pursue, and modify our drilling schedules in order to preserve the leases. We have no current plans to drill on acreage in other areas outside of our core area of operations.

At December 31, 2018, we had estimated proved reserves of approximately 85.2 MMBoe comprised of 50.7 MMBbls of crude oil, 17.1 MMBbls of natural gas liquids, and 104.7 Bcf of natural gas. The following table sets forth, at December 31, 2018, these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Oil (MBbls)	24,672	25,982	50,654
Natural Gas Liquids (MBbls)	7,740	9,360	17,100
Natural Gas (MMcf)	44,743	60,006	104,749
Equivalent (MBoe)[(1)]	39,869	45,343	85,212

(1) *Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.*

At December 31, 2018, total estimated proved reserves were approximately 85.2 MMBoe, a 34.1 MMBoe net increase over the previous year's estimate of 51.1 MMBoe. The net increase in total proved reserves was the result of additions and extensions of 53.2 MMBoe and acquisitions totaling 3.7 MMBoe, partially offset by net negative revisions of 17.6 MMBoe and production of 5.1 MMBoe.

At December 31, 2018, our estimated proved undeveloped (PUD) reserves were approximately 45.3 MMBoe, a 10.2 MMBoe net increase over the previous year's estimate of 35.1 MMBoe. The net increase in total proved undeveloped reserves was the result of additions and extensions of 40.1 MMBoe, partially offset by net negative revisions of 17.9 MMBoe and development of 12.0 MMBoe.

As of December 31, 2018, all of our PUD reserves are planned to be developed within five years from the date they were initially recorded. During 2018, approximately $182.0 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

Reliable technologies were used to determine areas where PUD locations are more than one offset location away from a producing well. These technologies include seismic data, wire line openhole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic estimated ultimate recoveries from individual producing wells. Our management team has been a leader in data gathering and evaluation in these areas and was instrumental in developing

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consortiums that allow various operators to exchange data. We relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves. Out of total proved undeveloped reserves of 45.3 MMBoe at December 31, 2018, 10.8 MMBoe were associated with 10 gross PUD locations that were more than one offset location from a producing well.

The estimates of quantities of proved reserves contained in this report were made in accordance with the definitions contained in SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. For additional information on our oil and natural gas reserves, including a table detailing the changes by year of our proved reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data "Supplemental Oil and Gas Information (Unaudited)."* We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations. Accordingly, all costs incurred in the acquisition, exploration, and development of proved and unproved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, direct internal costs and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. See further discussion in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 6,*"Oil and Natural Gas Properties."*

Capitalized costs of our evaluated and unevaluated properties at December 31, 2018, 2017 and 2016 are summarized as follows (in thousands):

	December 31, 2018	**December 31, 2017**	**December 31, 2016**
Oil and natural gas properties (full cost method):			
Evaluated	$ 1,470,509	$ 877,316	$ 1,269,034
Unevaluated	971,918	765,786	316,439
Gross oil and natural gas properties	2,442,427	1,643,102	1,585,473
Less accumulated depletion	(639,951)	(570,155)	(465,849)
Net oil and natural gas properties	$ 1,802,476	$ 1,072,947	$ 1,119,624

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The following table summarizes our oil, natural gas and natural gas liquids production volumes, average sales price per unit and average costs per unit. In addition, this table summarizes our production for each field that contains 15% or more of our total proved reserves:

	Successor			Predecessor
	Years Ended December 31,		Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016
	2018	2017		
Production:				
Crude oil MBbl				
Delaware	3,544	919		
Bakken / Three Forks	14	6,235	2,639	5,282
El Halcón		302	566	1,613
Other		55	45	223
Total	3,558	7,511	3,250	7,118
Natural gas MMcf				
Delaware	4,607	1,230		
Bakken / Three Forks		4,584	1,966	4,003
El Halcón		198	314	817
Other		1,427	731	1,740
Total	4,607	7,439	3,011	6,560
Natural gas liquids MBbl				
Delaware	749	218		
Bakken / Three Forks		924	384	791
El Halcón		41	78	213
Other		66	39	92
Total	749	1,249	501	1,096
Production:				
Total MBoe[(1)]	5,075	10,000	4,253	9,307
Average daily production Boe[(1)]	13,904	27,397	37,637	36,787
Average price per unit:				
Crude oil price Bbl	$ 56.10	$ 45.36	$ 43.01	$ 34.85
Natural gas price Mcf	1.47	2.18	2.24	1.45
Natural gas liquids price Bbl	25.55	15.19	12.01	7.23
Barrel of oil equivalent price Boe[(1)]	44.44	37.58	35.87	28.53
Average cost per Boe:				
Production:				
Lease operating	$ 4.94	$ 6.17	$ 5.26	$ 5.38
Workover and other	1.69	2.17	2.47	2.42
Taxes other than income	2.52	3.08	2.91	2.63
Gathering and other	11.84	4.08	3.45	3.15

(1) *Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.*

The average crude oil and natural gas sales prices above do not reflect the impact of cash paid on, or cash received from, settled derivative contracts as these amounts are reflected as "*Net gain (loss) on*

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derivative contracts" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact, for the year ended December 31, 2018, the average crude oil sales price was $56.82 per Bbl, the average natural gas sales price was $1.90 per Mcf and the average natural gas liquids sales price was $30.68 per Bbl. Including this impact, for the year ended December 31, 2017, the average crude oil sales price was $47.62 per Bbl and the average natural gas sales price was $2.29 per Mcf. Including this impact, during the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, average crude oil sales prices were $68.99 and $69.25 per Bbl, respectively and average natural gas sales prices were $2.33 and $1.58 per Mcf, respectively.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Markets and Major Customers

The purchasers of our oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, we have not experienced any significant losses from uncollectible accounts. In 2018, two individual purchasers of our production, Sunoco, Inc. and Western Refining, Inc., each accounted for more than 10% of total sales, collectively representing 77% of our total sales for the period. In 2017 and 2016, two individual purchasers of our production, Crestwood Midstream Partners and Suncor Energy Marketing, Inc., each accounted for more than 10% of total sales, collectively representing 58% of our total sales for each year.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to be overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities.

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Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other events may cause accidental releases of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our operating results, financial position or cash flows. For further discussion on risks see Item 1A. *Risk Factors*.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form spacing units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration and production to proceed.

The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to 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. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically govern the permitting, construction and operation of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

Beyond existing requirements, new programs and changes in existing programs may address various aspects of our business, including natural occurring radioactive materials, oil and natural gas exploration and production, air emissions, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to lift the existing exemption for oil and gas wastes and reclassify them as hazardous wastes or to subject them to enhanced solid waste regulation. If such proposals were to be enacted, they could have a significant impact on our operating costs and on those of all the industry in general. In the ordinary course of our operations, moreover some wastes generated in connection with our exploration and production activities may be regulated as solid waste under RCRA, as hazardous waste under existing RCRA regulations or as hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. Under CERCLA, RCRA and analogous state laws, we have been and may be required to remove or remediate such materials or wastes.

Water Discharges

Our operations also may be subject to the federal Clean Water Act and analogous state statutes. Those laws regulate discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil. In the event of a discharge of oil into U.S. waters, we could be liable under the Oil Pollution Act for cleanup costs, damages and economic losses.

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act (SDWA), the Underground Injection Control (UIC) regulations promulgated under the SDWA, and related state programs regulate the drilling and operation of salt water disposal wells. The United States Environmental Protection Agency (EPA) directly administers the UIC program in some states, and in others it is delegated to the state. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

Our completion operations are subject to regulation, which may increase in the short- or long-term. In particular, the well completion technique known as hydraulic fracturing, which is used to stimulate production of oil and natural gas, has come under increased scrutiny by the environmental community, and many local, state and federal regulators. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depths to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with substantially all of the wells for which we are the operator.

Working at the direction of Congress, the EPA issued a study in 2016 finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. The EPA also promulgated pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations to municipal sewage treatment plants. Beyond that, several environmental groups have petitioned the EPA to extend toxic release reporting requirements under the Emergency Planning and Community Right-to-Know Act to the oil and natural gas extraction industry and to require disclosure under the Toxic Substances Control Act of chemicals used in fracturing. Congress might likewise consider legislation to amend the federal SDWA to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Various states, including Texas, already have issued similar disclosure rules.

In addition, the Department of the Interior promulgated regulations concerning the use of hydraulic fracturing on lands under its jurisdiction, which includes lands on which we conduct or plan to conduct operations. While the Trump Administration rescinded those rules, that decision is being challenged in court. Regardless of how the federal issues are eventually resolved, states have been imposing new restrictions or bans on hydraulic fracturing. Even local jurisdictions, such as Denton, Texas and several cities in Colorado, have adopted, or tried to adopt, regulations restricting hydraulic fracturing. Additional hydraulic fracturing requirements at the federal, state or local level may limit our ability to operate or increase our operating costs.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through permitting programs and the imposition of other requirements. In addition, the EPA has developed and may continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or

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the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

In 2012 and 2016, the EPA issued air regulations for the oil and natural gas industry that address emissions from certain new sources of volatile organic compounds, sulfur dioxide, air toxics, and methane. The rules included the first federal air standards for natural gas and oil wells that are hydraulically fractured, or refractured, as well as requirements for other processes and equipment, including storage tanks. Compliance with these regulations has imposed additional requirements and costs on our operations. The Trump Administration may rescind some of the 2016 requirements, but supporters of the existing regulations likely would seek judicial review of any such decision.

In October 2015, the EPA announced that it was lowering the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion. Implementation will take place over several years; however, the new standard could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response, governments increasingly have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and several countries, including those comprising the European Union, have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have been implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emissions targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the EPA has issued regulations requiring us and other companies to annually report certain greenhouse gas emissions from oil and natural gas facilities. Beyond its measuring and reporting rules, the EPA has issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step in issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities.

In addition, the Obama Administration developed a Strategy to Reduce Methane Emissions that was intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels. Consistent with that strategy, the EPA issued air rules for oil and gas production sources, and the federal Bureau of Land Management (BLM) promulgated standards for reducing venting and flaring on public lands. The Trump Administration has been trying to roll back many of the Obama-era policies and rules; however, the long-term direction of federal climate regulation is uncertain.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and reduce demand for our products.

The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act and the Clean Water Act. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties may result.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees.

Employees and Principal Office

As of December 31, 2018, we had 116 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

As of December 31, 2018, we leased corporate office space in Houston, Texas at 1000 Louisiana Street, where our principal offices are located. We also lease corporate office space in Denver, Colorado.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Forms 3, 4 and 5 filed on behalf of directors and officers, and any amendments to such reports, available free of charge through our corporate website at *www.halconresources.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our insider trading policy, regulation FD policy, equity-based incentive grant policy, corporate governance guidelines, code of conduct, code

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of ethics, audit committee charter, compensation committee charter, nominating and corporate governance committee charter and reserves committee charter are available on our website under the heading "Investors Corporate Governance". Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our chief executive officer and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC's website at *www.sec.gov*. Unless specifically incorporated by reference in this Annual Report on Form 10-K, information that you may find on our website is not part of this report.

ITEM 1A. RISK FACTORS

Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability, future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. Prices also affect the amount of cash flow we have available for capital expenditures and our ability to borrow and raise additional capital. The amount we are able to borrow under our Senior Credit Agreement is subject to periodic redeterminations based in part on the value of our estimated proved reserves which reflect current oil and natural gas prices and on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Oil and natural gas prices are volatile. Among the factors that affect volatility are:

- domestic and foreign supplies of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and maintain production levels;
- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or terrorist attacks;
- the level of consumer demand for oil and natural gas, including demand growth in developing countries, such as China and India;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand for oil and natural gas;
- the price and availability of alternative fuels and energy sources;
- the price and availability of foreign imports and domestic exports; and
- global economic conditions.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

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We are substantially dependent upon our drilling success on our Delaware Basin properties, which are largely undeveloped and with which we have less experience.

We divested substantially all of our proved reserves and production when we sold our assets located in the Williston Basin in North Dakota and in the El Halcón area of East Texas in 2017. The disposition of these assets, combined with our other recent acquisition and divestiture activities, transformed our Company from multiple basin operations in which we had years of accumulated operational experience and substantial proved developed acreage to a pure-play, single-basin operator in the Delaware Basin in West Texas, where we have less accumulated operational experience and largely unproven acreage. As a consequence, our future drilling success is subject to the greater risks associated with a more concentrated, largely undeveloped property portfolio in an area where we have less experience. If our drilling results are less than anticipated, or the risks associated with a more concentrated property portfolio, such as regional supply and demand factors and delays or interruptions in production from governmental regulation, transportation constraints, market limitations, water shortages or other conditions, adversely impact our ability to produce or market our production, it could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

Our business requires substantial capital expenditures primarily to fund our drilling program. We may also continue to selectively increase our acreage position, which would require capital in addition to the capital necessary to drill on our existing acreage. In addition, it is possible that we will acquire acreage in other areas that we believe are prospective for oil and natural gas production and expend capital to develop such acreage. We expect to use borrowings under our Senior Credit Agreement and proceeds from potential future capital markets transactions, if necessary, to fund capital expenditures that are in excess of our operating cash flow and cash on hand.

Our Senior Credit Agreement limits our borrowings to the lesser of the borrowing base and the total commitments. As of December 31, 2018, our Senior Credit Agreement had a borrowing base of $275.0 million. As of December 31, 2018, we had no indebtedness outstanding, approximately $1.0 million of letters of credit outstanding and approximately $274.0 million of borrowing capacity available under our Senior Credit Agreement. Our borrowing base is redetermined semi-annually, and may also be redetermined periodically at the discretion of our lenders. A reduction in our borrowing base could require us to repay borrowings, if any, in excess of the borrowing base. Our Senior Credit Agreement also contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio and (ii) a Current Ratio, each as defined in the Senior Credit Agreement. We have periodically sought amendments to the covenants contained in the Senior Credit Agreement, including the financial covenants, where we have anticipated difficulty in maintaining compliance. In the event we have difficulty in the future meeting the covenants under our Senior Credit Agreement, we would be required to seek additional relief, and there is no assurance that it would be granted. Failure to comply with the covenants in the Senior Credit Agreement may limit our ability to borrow, result in an event of default and cause amounts outstanding under the Senior Credit Agreement to become being immediately due and payable.

Additionally, the indenture governing our senior debt contains covenants limiting our ability to incur indebtedness unless we meet one of two alternative tests or utilize the limited exceptions available. The first test applies to all indebtedness and requires that, after giving effect to the incurrence of additional debt, our fixed charge coverage ratio (which is the ratio of our adjusted consolidated EBITDA (as defined in our indenture) to our adjusted consolidated interest expense over the trailing four fiscal quarters) will be at least 2.00:1.00. The second test allows us to incur additional indebtedness, beyond the limitations of the fixed charge coverage ratio test, as long as this additional debt is incurred under Credit Facilities (as defined in our indenture) and generally, the amount thereof

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is not more than, subject to certain exceptions, the greater of (i) $350 million, (ii) the borrowing base in effect under our Senior Credit Agreement, and (iii) 30% of our adjusted consolidated net tangible assets, or ACNTA. ACNTA is defined in our indenture and is determined primarily by the value of discounted future net revenues from proved oil and natural gas reserves plus the capitalized cost attributable to our unevaluated properties.

If we are not able to borrow sufficient amounts under our Senior Credit Agreement, or otherwise, and are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisitions and other activities, which could result in a decrease in our production of oil and natural gas, forfeiture of leasehold interests if we are unable or unwilling to renew them, and could force us to sell some of our assets on an untimely or unfavorable basis, each of which could have a material adverse effect on our results and future operations.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted rates of return.

Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon current and future market prices for our oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. The costs of drilling and completing a well are often uncertain, and are affected by many factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions; and
- compliance with governmental requirements.

If we are unable to accurately predict and control the costs of drilling and completing a well, we may be forced to limit, delay or cancel drilling operations.

Historically, we have had substantial indebtedness and we may incur substantially more debt in the future. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have approximately $625.0 million principal amount of debt as of December 31, 2018. As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount of cash flow we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes or adverse developments in our business or economic downturns impacting the industry in which we operate. Indebtedness under our Senior Credit Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have hedging arrangements that are effective in offsetting interest rate fluctuations.

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We may incur substantially more debt in the future. The indenture governing our outstanding senior notes contains restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute "indebtedness" as defined under the indenture or borrowing under our Senior Credit Agreement. At December 31, 2018, we had approximately $274.0 million of additional borrowing capacity available under our Senior Credit Agreement.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional shares of common or preferred stock on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

Actions of activist stockholders could be costly and time-consuming, divert management's attention and resources, and have an adverse effect on our business.

Fir Tree Capital Management LP Partners ("Fir Tree") disclosed in its Schedule 13D/A, filed on February 4, 2019, that it beneficially owns approximately 5.22% of our common stock. Fir Tree has publicly communicated its opinions regarding actions that it believes would increase value to our stockholders, including engaging in a process to sell the Company. We value the views of our stockholders, including Fir Tree, and are open to constructive discussions about such matters; nevertheless, Fir Tree (or other activist stockholders) could take actions that could be costly and time-consuming to us, disrupt our operations, and divert the attention of our board of directors, management, and employees, such as by engaging in a proxy contest, public insistence upon pursuing strategic combinations or other transactions, or other special requests. As a result, we may retain the services of various professionals to advise us in these matters, including legal, financial, and communications advisers, the costs of which may negatively impact our future financial results. In addition, perceived uncertainties as to our future direction, strategy, or leadership as a consequence of activist stockholder initiatives may result in the loss of potential business opportunities, harm our ability to attract new or retain existing investors, customers, directors, employees, or other partners, and adversely affect our ability to maximize the value of our Company over time.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

As of the date of this filing, our corporate credit rating was "CCC+" with a negative outlook by Standard and Poor's (S&P) and "B3" with a negative outlook by Moody's Investors Service (Moody's). A downgrade in our credit ratings could negatively impact our cost of capital and our ability to finance our business. If our credit rating were downgraded, it could be difficult for us to raise debt in the public debt markets and the cost of that new debt could be higher than debt we could raise with our current ratings. In addition, a downgrade could impact requirements for us to provide financial assurance of performance under contractual arrangements or derivative agreements.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas

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formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Our future oil and natural gas reserves and production and, therefore, our cash flows and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition, results of operations, cash flows and potentially the borrowing capacity under our Senior Credit Agreement.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves. The process of estimating oil and natural gas reserves in accordance with SEC requirements is complex, involving significant estimates and assumptions in the evaluation of available geological, geophysical, engineering and economic data. Accordingly, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The estimates of our reserves as of December 31, 2018 are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, in accordance with SEC requirements, estimates of oil and gas reserves, future net revenue from proved reserves and the present value of our oil and gas properties are based on the assumption that future oil and gas prices remain the same as the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2018. Average prices for oil and natural gas for the 12-month period were as follows: WTI crude oil spot price of $65.56 per Bbl, adjusted by lease or field for quality, transportation fees, and market differentials and a Henry Hub natural gas spot price of $3.100 per MMBtu, as adjusted by lease or field for energy content, transportation fees, and market differentials. Any significant variance in the actual future prices from these assumptions could materially affect the estimated quantity and value of our reserves set forth in this report.

In addition, at December 31, 2018, approximately 53% of our estimated proved reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Estimated proved reserves as of December 31, 2018 assume that we will make future capital expenditures of approximately $413.0 million in the aggregate primarily from 2019 through 2023, which are necessary to develop and realize the value of proved reserves on our properties. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations, however, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate enough cash flow from operations or be able to raise sufficient capital to do so. Commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we conduct may not be successful or result in additional proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

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.

As of December 31, 2018, we owned leasehold interests in approximately 56,900 net acres in the Delaware Basin in West Texas of which approximately 27,600 net acres are undeveloped. Unless production in paying quantities is established on units containing these leases during their terms or unless we pay (to the extent we have the contractual right to pay) delay rentals or obtain other extensions to maintain the leases, these leases will expire. If our leases expire, we will lose our right to develop the related properties. We have no current plans to drill on acreage in other areas outside of our core area of operations.

Our drilling plans are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of our acreage is located in sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and are therefore subject to additional risk of expirations.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management and operational decisions necessary to manage our business within a challenging and highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Additionally, several of our senior executives recently departed to pursue other opportunities, including our former chief executive officer, and we have begun a search to replace him. Under these conditions, we could be unable to attract qualified personnel or have difficulty retaining our key personnel. The loss of the services of any of our remaining executive officers or other key employees for any reason and the inability to replace those key personnel could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our oil and natural gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in, the prospects in which we have or will acquire an interest. Such risks and hazards include:

- human error, accidents and other events beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;

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- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- well-on-well interference that may reduce recoveries;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or salt water, into the environment;
- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

As a result of these risks, expenditures, quantities and rates of production, revenues and operating costs may be materially affected and may differ materially from those anticipated by us.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems available in our operating areas, it will be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks or trains to transport our production, which is more expensive and less efficient than transportation via pipeline. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions, the availability and cost of capital, regulatory restrictions and judicial challenges. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently expect, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of weather conditions (which may worsen due to climate changes), accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

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We could experience periods of higher costs for various reasons, including due to higher commodity prices, increased drilling activity in the Delaware Basin and trade disputes that affect the costs of steel and other raw materials that we and our vendors rely upon, which could adversely affect our ability to execute our exploration and development plans on a timely basis and within budget.

Our industry is cyclical. When oil, natural gas and natural gas liquids prices increase, shortages of drilling rigs, equipment, supplies, water or qualified personnel may result. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production, particularly in the Delaware Basin, likewise may increase demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. Cost increases may also result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other materials that we and our vendors rely upon and increases in the cost of services to process, treat and transport our production. Recently, for instance, the President exercised his authority to impose significant tariffs on imports of steel and aluminum from a number of countries. Steel is extensively used by us and those in oil and gas industry generally, including for such items as tubulars, flanges, fittings and tanks, among many other items. As a result of the imposition of such tariffs, we will be paying significantly more for most or all of these items in the near term. Any escalation or expansion of tariffs could result in higher costs and affect a greater range of materials we rely upon in our business. The unavailability or high cost of drilling rigs, pressure pumping equipment, tubulars and other supplies, and of qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment and related services, we may enter into contracts that extend over several months or years. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We are subject to various contractual limitations that affect the discretion of our management in operating our business.

The indenture governing our debt and our Senior Credit Agreement contain various provisions that may limit our management's discretion in certain respects. In particular, these agreements limit our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase shares of our common stock and any other capital stock we may issue;
- make loans to others;
- make investments;
- incur additional indebtedness;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;

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- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

Compliance with these and other limitations may limit our ability to operate and finance our business and engage in certain transactions in the manner we might otherwise. In addition, if we fail to comply with the limitations under our indenture or Senior Credit Agreement, our creditors, to the extent the agreements so provide, may accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us.

Our business is highly competitive.

The oil and natural gas industry is highly competitive, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

We are subject to complex federal, state, local and other laws and regulations that frequently are amended to impose more stringent requirements that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our activities, we may not be able to conduct our operations as planned. We also may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, air emissions, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- pipeline construction;

- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with applicable laws may result in the suspension or termination of operations and subject us to liabilities, including administrative, civil and criminal penalties. Compliance costs can

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be significant. Moreover, the laws governing our operations or the enforcement thereof could change in ways that substantially increase our costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations.

Under environmental, health and safety laws and regulations, we also could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages including the assessment of natural resource damages. Such laws may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling and pipeline projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation by oil and natural gas producing states relating to conservation practices and protection of correlative rights. Such regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. By way of example, in 2015 the EPA lowered the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion. Implementation will take place over several years; however, the new standard eventually could result in more stringent emissions controls and additional permitting obligations for our operations.

Our strategy involves drilling in shale formations, using horizontal drilling and completion techniques. The results of our drilling program using these techniques may be subject to more uncertainties than conventional drilling programs, especially in areas that are new and emerging. These uncertainties could result in an inability to meet our expectations for reserves and production.

The results of our drilling in shale 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; consequently our predictions of drilling results in these areas are more uncertain. In addition, the use of horizontal drilling and completion techniques used in shale formations involve certain risks and complexities that do not exist in conventional wells. The ultimate success of our drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

If our drilling results are less than anticipated our investment in these areas may not be as attractive as we anticipate and could result in material write-downs of unevaluated properties and future declines in the value of our undeveloped acreage.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Federal, state and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we currently conduct operations, or in the future plan to conduct operations. Consequently, we could be subject to additional levels of regulation, operational delays or increased operating costs and could have additional regulatory burdens imposed upon us that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to amend the federal SDWA to require federal permitting of hydraulic fracturing and the disclosure of chemicals used in the hydraulic fracturing process. Further, the EPA issued a study in 2016 finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. Other governmental reviews have also been conducted that focus on environmental aspects of hydraulic fracturing. Such activities eventually could result in additional regulatory scrutiny that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Certain states, including Texas where we conduct our operations, likewise are considering or have adopted more stringent requirements for various aspects of hydraulic fracturing operations, such as permitting, disclosure, air emissions, well construction, seismic monitoring, waste disposal and water use. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing.

The proliferation of regulations may limit our ability to operate. If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response, governments increasingly have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and international negotiations over climate change and greenhouse gases are continuing. Meanwhile, several countries, including those comprising the European Union, have established greenhouse gas regulatory systems.

In the United States, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emission targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration addressed climate change through a variety of administrative actions. The EPA thus issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, then President Obama released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and gas sector. Consistent with that strategy, the EPA issued final rules in 2016 for new and modified oil and gas production sources (including hydraulically fractured oil wells, natural gas well sites, natural gas processing plants, natural gas gathering and boosting stations and natural gas transmission sources) to reduce emissions of methane as well as volatile organic compound and toxic pollutants. In addition, the BLM has promulgated standards for reducing venting and flaring on public lands. The Trump Administration has been trying to roll back many of the Obama-era policies and rules, but those efforts have resulted in court challenges. At this point, the long-term direction of federal climate regulation is uncertain.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have or contribute to significant greenhouse gas emissions. Such cases may seek emissions reductions, challenge air emissions or other permits or request damages for alleged climate change impacts to the environment, people, and property.

The direction of future U.S. climate change regulation is difficult to predict given the current uncertainties surrounding the policies of the Trump Administration. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions from the oil and gas industry. Even in the absence of federal efforts in this area, states may continue pursuing climate regulations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our products.

Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner.

Water is an essential component of our drilling and hydraulic fracturing processes. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, natural gas liquids and natural gas, which could have an adverse effect on our business, financial condition and results of operations. Wastewaters from our operations typically are disposed of via underground injection. Some studies have linked earthquakes in certain areas to underground injection, which is leading to greater public scrutiny and regulation of disposal wells. Any new environmental initiatives or regulations that restrict injection of fluids, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas, or that limit the withdrawal, storage or use of surface water or ground water necessary for hydraulic fracturing of our wells, could increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

The ongoing implementation of federal legislation enacted in 2010 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.

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 (or CFTC), along with other federal agencies, to promulgate regulations implementing the new legislation.

The CFTC has finalized many 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 under margin rules

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that are being phased in between 2016 and 2020, some registered swap dealers may require us to post margin 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.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover claims made against us in the future.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

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Our financial results following the sale of our Williston Basin and El Halcón assets will not be comparable to our historical financial results and historical trends may not be indicative of our future results.

We divested substantially all of our proved reserves and production when we sold our assets located in the Williston Basin in North Dakota and in the El Halcón area of East Texas in 2017. The dispositions of these assets, combined with our other recent acquisition and divestiture activities, have substantially transformed us into a pure-play, single-basin company focused on developing largely unproven acreage concentrated in the Delaware Basin in West Texas. Our historical financial information in this report includes the operations of our Williston Basin and El Halcón assets for periods prior to their sale and does not reflect the operations of our Delaware Basin assets in all periods. As a result, our historical financial results will not be comparable to our future results and historical trends may not be indicative of results to be expected in future periods.

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

In general, under Section 382 of the Internal Revenue Code of 1986, as amended, a corporation that undergoes an "ownership change" is subject to limitations on its ability to utilize its pre-change net operating losses (NOLs), and realized built in losses (RBILS), to offset future taxable income. In general, an ownership change occurs if the aggregate stock ownership of certain stockholders (generally 5% stockholders, applying certain look-through rules) increases by more than 50 percentage points over such stockholders' lowest percentage ownership during the testing period (generally three years).

We experienced an ownership change in September 2016 as a result of the consummation of our plan of reorganization under chapter 11 of the U.S. Bankruptcy Code and we may experience additional ownership changes in the future. Limitations imposed on our ability to use NOLs and RBILS to offset future taxable income may cause U.S. federal income taxes to be paid earlier than otherwise would be paid if such limitations were not in effect and could cause such NOLs and RBILS to expire unused, in each case reducing or eliminating the benefit of such NOLs and RBILS. Similar rules and limitations may apply for state income tax purposes.

An additional ownership change was experienced in December 2018 due to the aggregate stock ownership of certain stockholders increasing by more than 50 percentage points over their lowest percentage ownership during the testing period (see discussion above).

We may be required to take non-cash asset write-downs.

We may be required under full cost accounting rules to write-down the carrying value of oil and natural gas properties if oil and natural gas prices decline or if there are substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. We utilize the full cost method of accounting for oil and natural gas exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or "ceiling," of the book value of oil and natural gas properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges when hedge accounting is applied, calculated using the unweighted arithmetic average of the first day of each month for the 12-month period ending at the balance sheet date. If the net book value of oil and natural gas properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds the ceiling limitation, SEC regulations require us to impair or "write-down" the book value of our oil and natural gas properties.

As of December 31, 2018, our net book value of oil and natural gas properties did not exceed our ceiling amount using the WTI unweighted 12-month average spot price $65.56 per Bbl for oil and natural gas liquids and the Henry Hub unweighted 12-month average spot price of $3.100 per MMBtu for natural gas. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is impossible to predict the likelihood, timing and magnitude of any future impairments. Depending on the magnitude, a ceiling test write-down could negatively affect our results of operations.

Costs associated with unevaluated properties, which were approximately $971.9 million at December 31, 2018, are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to depletion and the ceiling test limitation.

Future sales of our common stock in the public market or the issuance of securities senior to our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and our ability to raise funds in stock offerings.

A large percentage of our shares of common stock are held by a relatively small number of investors. Further, we entered into registration rights agreements with certain of those investors pursuant to which we filed a registration statement with the SEC to facilitate potential future sales of such shares by them. Sales by us or our stockholders of a substantial number of shares of our common stock in the public markets, or even the perception that these sales might occur, could cause the market price of our common stock to decline or could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

We are currently authorized to issue 1.0 billion shares of common stock and 1.0 million shares of preferred stock, with such designations, rights, preferences, privileges and restrictions as determined by the board of directors. As of March 4, 2019, we had outstanding approximately 160.3 million shares of common stock and warrants and options to purchase an aggregate of 12.1 million shares of our common stock. As of March 4, 2019, we have also reserved an additional 5.1 million shares for future issuance to our directors, officers and employees as restricted stock or stock option awards pursuant to our 2016 Long-Term Incentive Plan. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock.

We may issue common stock or other equity securities senior to our common stock in the future for a number of reasons, including to finance acquisitions, to adjust our leverage ratio, and to satisfy our obligations upon the exercise of warrants and options, or for other reasons. We cannot predict the effect, if any, that future sales or issuances of shares of our common stock or other equity securities, or the availability of shares of common stock or such other equity securities for future sale or issuance, will have on the trading price of our common stock.

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.

We will be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult and may involve unexpected costs or delays.

We have completed in the past and may complete in the future significant acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy, which may include the acquisition of asset packages of producing properties, undeveloped acreage or existing companies or businesses operating in our industry. The successful acquisition of assets in our industry requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and natural gas liquids prices and their appropriate differentials;
- development and 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. Our review 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 potential recoverable reserves. Inspections may not always be performed on every well or well site, and environmental problems 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. We are generally not able to obtain contractual indemnification for environmental liabilities and normally acquire properties on an "as is" basis.

Significant acquisitions of existing companies or businesses and other strategic transactions may involve additional risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with our own while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- the challenge of integrating environmental compliance systems to meet requirements of rapidly changing regulations;

- the challenge of attracting and retaining personnel associated with acquired operations; and

- failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within our expected time frame.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our

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business. If our senior management is not able to manage the integration process effectively, or if any significant business activities are interrupted as a result of the integration process, our business could be materially and adversely affected.

We depend on computer, telecommunications and information technology systems to conduct our business, and failures, disruptions, cyber-attacks or other breaches in data security could significantly disrupt our business operations, create liability and increase our costs.

The oil and natural gas industry in general has become increasingly dependent upon technology to conduct day-to-day operations, including certain exploration, development and production activities. We have agreements with third parties for hardware, software, telecommunications and other information technology services necessary to our business and have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We use these systems and data to, among other things, estimate quantities of oil, NGL and natural gas reserves, process and record financial data and communicate with our employees and third parties. Failures in these systems due to hardware or software malfunctions, computer viruses, natural disasters, fire, human error or other causes could significantly affect our ability to conduct our business. In particular, cyber-security attacks on systems are increasing in frequency and sophistication and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to them, there can be no assurance that these procedures and controls will be sufficient to prevent security threats from materializing and any interruptions to our arrangements with third parties, to our computing and communications infrastructure or our information systems could significantly disrupt our business operations. Further, the loss or corruption of sensitive information could have a material adverse effect on our reputation, financial position, results of operations or cash flows. In addition, as cyber-attacks 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 vulnerability to cyber-attacks. We generally do not maintain insurance coverage for the costs associated with cyber-security events.

Our actual financial results may vary materially from the projections that we filed with the bankruptcy court in connection with the confirmation of our plan of reorganization.

In connection with the disclosure statement we filed with the bankruptcy court, and the hearing to consider confirmation of our plan of reorganization, we prepared projected financial information to demonstrate to the bankruptcy court the feasibility of the plan of reorganization and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance and with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

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Our historical financial information may not be indicative of our future financial performance.

Effective upon our emergence from chapter 11 bankruptcy on September 9, 2016, we adopted fresh-start accounting, as a consequence of which our assets and liabilities were adjusted to fair values and we had no beginning or ending retained earnings or deficit balances on that date. Accordingly, our financial condition and results of operations following our emergence from chapter 11 bankruptcy will not be comparable to the financial condition and results of operations reflected in our historical financial statements. Further, as a result of the implementation of our plan of reorganization and the transactions contemplated thereby, our historical financial information may not be indicative of our future financial performance.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1. *Business* and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 11*, "Commitments and Contingencies,"* and is incorporated herein by reference.

From time to time, we may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of our business. While the outcome and impact of currently pending legal proceedings cannot be determined, our management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material effect on our consolidated operating results, financial position or cash flows.

Under rules promulgated by the SEC, administrative or judicial proceedings arising under any federal, state or local provisions that have been enacted or adopted regulating the discharge of materials into the environment or primarily for the purpose of protecting the environment are disclosed if the governmental authority is party to such proceeding and the proceeding involves potential monetary sanctions of $100,000 or more. We are not party to any such proceedings, except as described below.

On September 17, 2018, the EPA approved a Consent Agreement entered into among us, one of our subsidiaries and the EPA (Region 8), resolving alleged failures by us to minimize leakage of natural gas emissions into the atmosphere as required by EPA regulations at certain oil and natural gas wells located in Fort Berthold, North Dakota. We sold all of the wells subject to the Consent Agreement, together with our other operated properties in North Dakota, in September 2017. The EPA provided us with notice of the alleged violations in January 2018, which we promptly contested. In entering into the Consent Agreement, neither we nor our subsidiary admitted the facts or violations alleged by the EPA. Pursuant to the terms of the Consent Agreement, we paid a civil penalty of $110,000 to the EPA in September 2018.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Our common stock trades on the New York Stock Exchange (NYSE) under the symbol HK.

We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including our prospects, and such other factors, as the board of directors deems relevant. We are also restricted from paying cash dividends on common stock under our Senior Credit Agreement and under the terms of the indenture governing our other long-term debt.

Approximately 480 registered stockholders of record as of March 4, 2019 held our common stock. In many instances, a stockholder can hold shares through a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to the surrender of our common stock by employees in exchange for the payment of certain tax withholding obligations during the three months ended December 31, 2018.

	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 Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 2018		$		
November 2018				
December 2018	19,797	1.96		

(1) *All of the shares were surrendered by employees in exchange for the payment of tax withholding upon the vesting of restricted stock awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our common stock.*

Stock Performance Graph

The following graph and table compare the cumulative total return to our stockholders on our common stock beginning with the commencement of trading upon our emergence from chapter 11 bankruptcy on September 12, 2016 through December 31, 2018, relative to the cumulative total returns of the NYSE Composite Index and the S&P Oil & Gas Exploration & Production Index for the same period. The comparison assumes an investment of $100 (with reinvestment of all dividends at the average of the closing stock prices at the beginning and end of the quarter) was made in our common stock on September 12, 2016, and in each of the indexes, and relative performance is tracked through December 31, 2018. The identity of the companies included in the S&P Oil & Gas Exploration & Production Index will be provided upon request.

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COMPARISON OF 28 MONTH CUMULATIVE TOTAL RETURN*

Among Halcón Resources Corporation, the NYSE Composite Index,
and S&P Oil & Gas Exploration & Production Index

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* *$100 invested on 9/12/16 in stock or 8/31/16 in index, including reinvestment of dividends. Fiscal year end is December 31.*

Value of Initial $100 Investment

		Years Ended December 31,		
	September 12, 2016	**2016**	**2017**	**2018**
Halcón Resources Corporation	$ 100	$ 86	$ 70	$ 16
NYSE Composite	100	104	123	112
S&P Oil & Gas Exploration & Production Index	100	100	74	48

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ITEM 6. SELECTED FINANCIAL DATA

Prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, September 9, 2016.

The following table presents selected historical financial data derived from our consolidated financial statements. The following data is only a summary and should be read with our historical consolidated financial statements and related notes contained in this document. Refer to the footnotes in Item 8. *Consolidated Financial Statements and Supplementary Data,* for details regarding our reorganization and adoption of fresh-start accounting, as well as other transactions that could impact the comparability of the following data (in thousands, except per share data):

	Successor			Predecessor		
	Years Ended December 31,		Period from September 10, 2016 through December 31,	Period from January 1, 2016 through September 9,	Years Ended December 31,	
	2018[6]	2017[7]	2016[8]	2016[9]	2015[10]	2014[11]
Income Statement Data:						
Total operating revenues	$ 226,609	$ 377,965	$ 153,362	$ 266,843	$ 550,278	$ 1,148,261
Income (loss) from operations	92,140	715,423	(415,799)	(851,617)	(2,744,506)	(58,387)
Net income (loss)	45,959	535,686	(479,193)	11,958	(1,922,621)	315,956
Net income (loss) available to common stockholders	45,959	487,679	(479,984)	(32,794)	(2,006,958)	282,942
Net income (loss) per share of common stock[1]:						
Basic	$ 0.29	$ 3.67	$ (5.26)	$ (0.27)	$ (18.66)	$ 3.40
Diluted	$ 0.29	$ 3.65	$ (5.26)	$ (0.27)	$ (18.66)	$ 2.93

	Successor			Predecessor	
	As of December 31,			As of December 31,	
	2018	2017	2016	2015	2014
Balance sheet data:					
Working capital (deficit)	$ (17,090)	$ 321,457	$ (46,904)	$ 261,345	$ (41,977)
Total assets	2,083,609	1,643,620	1,319,670	3,458,692	6,383,227
Total long-term debt, net[2][3]	613,105	409,168	964,653	2,873,637	3,695,488
Redeemable noncontrolling interest[4]				183,986	117,166
Stockholders' equity[5]	1,197,044	1,071,998	112,688	52,414	1,772,169

(1) *No cash dividends on our common stock were declared or paid for any periods presented.*

(2) *Excludes current portion of long-term debt for all periods presented.*

(3) *On September 9, 2016, upon emergence from chapter 11 bankruptcy, approximately $2.0 billion of our senior notes were cancelled. Refer to Item 8. Consolidated Financial Statements and Supplementary Data Note 2, "Reorganization," for additional information.*

(4)

On June 16, 2014, HK TMS, LLC (HK TMS), which was then a wholly owned subsidiary of ours, entered into a transaction with funds and accounts managed by Apollo Global Management, LLC (Apollo), by initially selling 150,000 preferred shares in HK TMS (Membership Interests). On

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September 30, 2016, Apollo acquired one hundred percent of the common shares of HK TMS and assumed all obligations relating to the Membership Interests. For additional information regarding these transactions, see Item 8. Consolidated Financial Statements and Supplementary Data Note 5, "Acquisitions and Divestitures."

(5) *On September 9, 2016, upon emergence from chapter 11 bankruptcy, all existing shares of Predecessor common stock were cancelled and the Successor Company issued approximately 90.0 million shares of new common stock to the Predecessor Company's existing common stockholders, Third Lien Noteholders, Unsecured Noteholders, and the Convertible Noteholder. Refer to Item 8. Consolidated Financial Statements and Supplementary Data Note 2, "Reorganization," for further details.*

(6) *For the year ended December 31, 2018, we recorded a $119.0 million gain on the sale of our Water Assets. Refer to the footnotes included in Item. 8 Consolidated Financial Statements and Supplementary Data Note 5, "Acquisitions and Divestitures," for further details.*

(7) *For the year ended December 31, 2017, we recorded a $721.6 million gain on the sale of our oil and natural gas properties and a $114.9 million loss on the extinguishment of debt. Refer to the footnotes included in Item 8. Consolidated Financial Statements and Supplementary Data, for additional information regarding these events.*

(8) *For the period from September 10, 2016 through December 31, 2016, we recorded a $420.9 million full cost ceiling impairment on the carrying value of our oil and natural gas properties. Refer to Item 8. Consolidated Financial Statements and Supplementary Data Note 6, "Oil and Natural Gas Properties," for additional information.*

(9) *For the period from January 1, 2016 through September 9, 2016, we recorded a $754.8 million full cost ceiling impairment on the carrying value of our oil and natural gas properties, a $28.1 million impairment on other operating property and equipment, an $81.4 million gain on extinguishment of debt, and a $913.7 million gain on reorganization items due to fresh-start accounting. Refer to the footnotes in Item 8. Consolidated Financial Statements and Supplementary Data, for additional information regarding these events.*

(10) *For the year ended December 31, 2015, we recorded a $2.6 billion full cost ceiling impairment on the carrying value of our oil and natural gas properties and a $761.8 million gain on the extinguishment of debt.*

(11) *For the year ended December 31, 2014, we recorded a $239.7 million full cost ceiling impairment on the carrying value of oil and natural gas properties and a $35.6 million impairment on other operating property and equipment.*

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

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

Certain prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to September 9, 2016. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, September 9, 2016.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Overview

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. During 2017, we acquired certain properties in the Delaware Basin and divested our assets located in the Williston Basin in North Dakota (the Williston Divestiture) and in the El Halcón area of East Texas (the El Halcón Divestiture). As a result, our properties and drilling activities are currently focused in the Delaware Basin, where we have an extensive drilling inventory that we believe offers attractive economics. The Williston Divestiture improved our liquidity and significantly reduced our debt, better enabling us to accelerate development of our Delaware Basin properties and execute our growth plans in the basin.

At December 31, 2018, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell), using Securities and Exchange Commission (SEC) prices for crude oil and natural gas, which are based on the West Texas Intermediate crude oil spot price of $65.56 per Bbl and Henry Hub natural gas spot price of $3.100 per MMBtu, were approximately 85.2 MMBoe, consisting of 50.7 MMBbls of oil, 17.1 MMBbls of natural gas liquids, and 104.7 Bcf of natural gas. Approximately 47% of our proved reserves were classified as proved developed as of December 31, 2018. We maintain operational control of approximately 99% of our proved reserves. Substantially all of our proved reserves and production at December 31, 2018 are associated with our Delaware Basin properties.

Our total operating revenues for 2018 were approximately $226.6 million compared to total operating revenues for 2017 of approximately $378.0 million. Full year 2018 production averaged 13,904 Boe/d compared to average daily production of 27,397 Boe/d for 2017. The decrease in total operating revenues and average daily production year over year was driven by our divestitures in 2017 and was partially mitigated by the production associated with our assets located in the Delaware Basin and our drilling activities since acquiring the assets.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, transportation take-away capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

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In 2018, we incurred capital expenditures for drilling and completions of approximately $444.4 million. In 2018, we ran an average of three operated rigs in the Delaware Basin and participated in the drilling of 31 gross (30 net) operated wells, none of which were dry holes. We also completed 29 gross operated wells during 2018 and brought 29 gross operated wells on production. In 2019, we currently plan to spend approximately $190 million to $210 million on drilling and completions. Overall, we expect to drill 17 gross operated wells during 2019, complete 18 gross operated wells, bring 23 gross operated wells on production, and have five gross operated wells drilling over year-end 2019. Our 2019 drilling and completions budget currently contemplates running an average of two operated rigs in the Delaware Basin during the year, and is subject to change. In addition, we expect to spend approximately $60 million to $80 million on infrastructure, seismic and other in 2019.

We expect to fund our budgeted 2019 capital expenditures with cash and cash equivalents on hand, cash flows from operations and borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to maintain adequate borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and fund infrastructure projects. In the event our cash flows are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may be required to curtail drilling, development, land acquisitions and other activities to reduce our capital spending. However, significant or prolonged reductions in capital spending will adversely impact our production and may negatively affect our future cash flows.

Oil and natural gas prices are inherently volatile and sustained lower commodity prices could have a material impact upon our full cost ceiling test calculation. The ceiling test calculation dictates that we use the unweighted arithmetic average price of crude oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. Using the crude oil price for February 2019 of $55.26 per Bbl, and holding it constant for one month to create a trailing 12-month period of average prices that is more reflective of recent price trends, our ceiling amount related to the net book value of our oil and natural gas properties would have been reduced and would have generated a full cost ceiling impairment of approximately $15.5 million, holding all other inputs and factors constant. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties to our full cost pool, capital spending and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Recent Developments

Sale of Water Infrastructure Assets

On December 20, 2018, we sold our water infrastructure assets located in the Delaware Basin (the Water Assets) to WaterBridge Resources LLC (the Purchaser) for an adjusted purchase price of $214.1 million in cash (the Water Infrastructure Divestiture) at closing. The effective date of the transaction was October 1, 2018. Additional incentive payments of up to $25.0 million per year for the next five years are available subject to our ability to meet certain annual incentive thresholds relating to the number of wells connected to the Water Assets per year. Our ability to achieve the incentive thresholds will be driven by, among other things, our development program which will consider future market conditions and is subject to change.

Upon closing, we dedicated all of the produced water from our oil and natural gas wells within our Monument Draw, Hackberry Draw and West Quito Draw operating areas to the Purchaser. There are no drilling or throughput commitments associated with the Water Infrastructure Divestiture. The Purchaser will receive a current market price, subject to annual adjustments for inflation, in exchange for the transportation, disposal and treatment of such produced water, and the Purchaser will receive a market price for the supply of freshwater and recycled produced water provided to us.

Acquisition of West Quito Draw Properties

On February 6, 2018, one of our wholly owned subsidiaries entered into a Purchase and Sale Agreement (the Shell PSA) with SWEPI LP (Shell), an affiliate of Shell Oil Company, pursuant to which we agreed to purchase acreage and related assets in the Delaware Basin located in Ward County, Texas (the West Quito Draw Properties) for a total adjusted purchase price of $198.5 million. The effective date of the acquisition was February 1, 2018, and we closed the transaction on April 4, 2018. We funded the cash consideration of the acquisition of the West Quito Draw Properties with the net proceeds from our issuance of the Additional 2025 Notes (defined below) and common stock, both of which are discussed below.

Issuance of Additional 2025 Notes

On February 15, 2018, we issued an additional $200.0 million aggregate principal amount of our 6.75% senior notes due 2025 at a price to the initial purchasers of 103.0% of par (the Additional 2025 Notes). The Additional 2025 Notes were sold pursuant to the exemption from registration under the Securities Act and applicable state securities laws, including Rule 144A and Regulation S under the Securities Act. The net proceeds from the sale of the Additional 2025 Notes were approximately $202.4 million after initial purchasers' premiums and deducting commissions and offering expenses and a portion was used to fund the cash consideration for the acquisition of the West Quito Draw Properties and for general corporate purposes, including funding our 2018 drilling program. These notes were issued under the Indenture, dated as of February 16, 2017, among us, certain of our subsidiaries and U.S. Bank National Association, as trustee, which governs our 6.75% senior notes due 2025 that were issued on February 16, 2017 (the 2025 Notes). The Additional 2025 Notes are treated as a single class with, and have the same terms as the 2025 Notes, except that the Additional 2025 Notes will initially be subject to transfer restrictions and have the benefit of certain registration rights and provisions for the payment of additional interest in the event of a breach with respect to such registration rights.

In connection with the issuance of the Additional 2025 Notes, on February 15, 2018, we, our subsidiary guarantors and J.P. Morgan Securities, LLC, on behalf of itself and the initial purchasers, entered into a Registration Rights Agreement, pursuant to which we and our subsidiary guarantors agreed to, among other things, use reasonable best efforts to file a registration statement under the Securities Act and complete an exchange offer for the Additional 2025 Notes within 180 days after closing. We filed such registration statement on March 20, 2018 and it was declared effective by the SEC on April 9, 2018. In addition, we completed the exchange offer for the Additional 2025 Notes on May 17, 2018.

Issuance of Common Stock

On February 9, 2018, we sold 9.2 million shares of common stock, par value $0.0001 per share, in a public offering at a price of $6.90 per share. The net proceeds to us from the offering were approximately $60.4 million, after deducting underwriters' discounts and offering expenses.

Senior Revolving Credit Facility

On February 28, 2019, the lenders party to our Senior Credit Agreement issued a consent (the Severance and Office Payments Consent) to us whereby Severance Payments and Office Payments (as defined in the Severance and Office Payments Consent) may exceed the maximum level allowed for adding back non-recurring expenses and charges in the definition of EBITDA (as defined in the Senior

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Credit Agreement) when calculating the ratio of Consolidated Total Net Debt to EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarter ending March 31, 2019.

On February 15, 2019, we entered into the Seventh Amendment (the Seventh Amendment) to the Senior Credit Agreement which, among other things, provides for (i) the use of annualized financial data in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending March 31, 2019, June 30, 2019 and September 30, 2019 and (ii) amends the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA to be (a) 5.00 to 1.0 for the fiscal quarter ending March 31, 2019, (b) 4.75 to 1.0 for the fiscal quarter ending June 30, 2019, (c) 4.5 to 1.0 for the fiscal quarter ending September 30, 2019, (d) 4.25 to 1.0 for the fiscal quarter ending December 31, 2019, and (e) 4.0 to 1.0 for the fiscal quarter ending March 31, 2020 and any fiscal quarter thereafter.

On November 16, 2018, we entered into the Sixth Amendment (the Sixth Amendment) to the Senior Credit Agreement, which, among other things, provided for (i) provisions allowing for optional increases in the maximum Credit Amount (as defined in the Senior Credit Agreement) by us and the lenders party thereto. The Sixth Amendment also established the borrowing base at $350.0 million following the closing of the sale of the Water Assets; however, we and the lenders agreed to reduce the Aggregate Maximum Credit Amounts (as defined in the Senior Credit Agreement) to $275.0 million, thereby effectively limiting the amount available to borrow under the Senior Credit Agreement to $275.0 million.

On November 7, 2018, we entered into the Fifth Amendment (the Fifth Amendment) to the Senior Credit Agreement which, among other things, provided for (i) the use of annualized financial data in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending September 30, 2018, December 31, 2018, March 31, 2019, June 30, 2019 and September 30, 2019 and (ii) amended the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA of (a) 4.75 to 1.0 for the fiscal quarter ending September 30, 2018, (b) 4.25 to 1.0 for the fiscal quarter ending December 31, 2018 and (c) 4.0 to 1.0 for the fiscal quarter ending March 31, 2019 and any fiscal quarter thereafter.

On November 6, 2018, the lenders party to our Senior Credit Agreement issued a consent (the H2S Consent) to us whereby H2S Expenses (as defined in the H2S Consent) may exceed the maximum level allowed for adding back non-recurring expenses and charges in the definition of EBITDA (as defined in the Senior Credit Agreement) when calculating the ratio of Consolidated Total Net Debt to EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending September 30, 2018, December 31, 2018 and March 31, 2019.

During the year, we also periodically sought amendments to the covenants in the Senior Credit Agreement, including the financial covenants, where we anticipated difficulty in maintaining compliance. On July 12, 2018, we entered into the Fourth Amendment to the Senior Credit Agreement and on February 2, 2018, we entered into the Second Amendment to the Senior Credit Agreement. Refer to *"Capital Resources & Liquidity"* below for a further discussion of these amendments.

Option Agreement to Acquire Monument Draw Assets (Ward and Winkler Counties, Texas)

On December 9, 2016, one of our wholly owned subsidiaries entered into an agreement with a private company, pursuant to which it acquired the rights to purchase up to 15,040 net acres in the Monument Draw area of the Delaware Basin, located in Ward and Winkler Counties, Texas (the Ward County Assets) prospective for the Wolfcamp and Bone Spring formations. The Ward County Assets are divided into two tracts (the Southern Tract and the Northern Tract) with separate options for each tract. Pursuant to the terms of the agreement (as amended), on June 15, 2017, we purchased the Southern Tract for approximately $87.4 million and on January 9, 2018, we purchased the Northern Tract for approximately $108.2 million.

Capital Resources and Liquidity

Our near-term capital spending requirements are expected to be funded with cash and cash equivalents on hand, cash flows from operations and borrowings under our Senior Credit Agreement.

The Senior Credit Agreement contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement), which was recently revised by the H2S Consent, Severance and Office Payments Consent, and Seventh Amendment, as discussed below, and (ii) a Current Ratio (as defined in the Senior Credit Agreement) not to be less than 1.00:1.00. At December 31, 2018, we had no indebtedness outstanding, $1.0 million letters of credit outstanding and approximately $274.0 million of borrowing capacity available under our Senior Credit Agreement. After giving effect to the H2S Consent and the Fifth Amendment, at December 31, 2018, we were in compliance with the financial covenants under the Senior Credit Agreement.

As noted above, we have recently, and in the past, obtained amendments and consents to the covenants under our Senior Credit Agreement under circumstances where we anticipated that it might be challenging for us to comply with our financial covenants for a particular period of time. The basis for these amendments and consents was the potential for us to fall out of compliance as a result of our strategic decisions and unforeseen operational challenges. Specifically, on February 28, 2019, the lenders party to the Senior Credit Agreement issued a consent (the Severance and Office Payments Consent) to the Company whereby Severance Payments and Office Payments (as defined in the Severance and Office Payments Consent) may exceed the maximum level allowed for adding back non-recurring expenses and charges in the definition of EBITDA (as defined in the Senior Credit Agreement) when calculating the ratio of Consolidated Total Net Debt to EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarter ending March 31, 2019. On February 15, 2019, we entered into the Seventh Amendment among other things, provided for (i) the use of annualized financial data in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending March 31, 2019, June 30, 2019 and September 30, 2019 and (ii) amended the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA of (a) 5.00 to 1.0 for the fiscal quarter ending March 31, 2019, (b) 4.75 to 1.0 for the fiscal quarter ending June 30, 2019, (c) 4.5 to 1.0 for the fiscal quarter ending September 30, 2019, (d) 4.25 to 1.0 for the fiscal quarter ending December 31, 2019, and (e) 4.0 to 1.0 for the fiscal quarter ending March 31, 2020 and any fiscal quarter thereafter. On November 7, 2018, we entered into the Fifth Amendment to the Senior Credit Agreement which, among other things, provided for (i) the use of annualized financial data in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending September 30, 2018, December 31, 2018, March 31, 2019, June 30, 2019 and September 30, 2019 and (ii) amended the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA of (a) 4.75 to 1.0 for the fiscal quarter ending September 30, 2018, (b) 4.25 to 1.0 for the fiscal quarter ending December 31, 2018 and (c) 4.0 to 1.0 for the fiscal quarter ending March 31, 2019 and any fiscal quarter thereafter. On November 6, 2018, the lenders party to the Senior Credit Agreement issued the H2S Consent to us whereby H2S Expenses (as defined in the Consent) may exceed the maximum level allowed for adding back non-recurring expenses and charges in the definition of EBITDA (as defined in the Senior Credit Agreement) when calculating the ratio of Consolidated Total Net Debt to EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending September 30, 2018, December 31, 2018 and March 31, 2019. On July 12, 2018, we entered into the Fourth Amendment to the Senior Credit Agreement which provided for an increase in the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA (as defined in the Senior Credit Agreement) of (i) 4.75 to 1.0 for the fiscal quarter ending September 30, 2018, (ii) 5.0 to 1.0 for the fiscal quarters ending December 31, 2018, March 31, 2019 and June 30, 2019, (iii) 4.25 to 1.0 for the fiscal quarter ending September 30, 2019 and (iv) 4.0 to 1.0 for the fiscal quarter ending December 31, 2019 and any fiscal quarter thereafter; provided, however, that if we

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consummate a sale of all or a material portion of our midstream assets, then the ratio of Consolidated Total Net Debt to EBITDA shall be reduced to 4.0 to 1.0 for each fiscal quarter ending after the fiscal quarter in which such sale is consummated. On February 2, 2018, we entered into the Second Amendment to our Senior Credit Agreement. The Second Amendment, among other things, provides for (i) the use of annualized financial information in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending June 30, 2018, September 30, 2018 and December 31, 2018, (ii) an increase in the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA of 4.50:1.00 for the fiscal quarter ending June 30, 2018, and a ratio of 4.00:1.00 for any fiscal quarter thereafter, (iii) a waiver of compliance with the covenant relating to the Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement) for the fiscal quarter ending March 31, 2018, and (iv) a waiver of the automatic reduction to the borrowing base that would otherwise result due to the issuance of the Additional 2025 Notes.

Our strategic decision to transform into a pure-play, single basin company focused on the Delaware Basin in West Texas resulted in us divesting our producing properties located in other areas and acquiring primarily undeveloped acreage in the Delaware Basin. Our drilling activities since acquiring the assets required significant capital expenditure outlays to replace lost production and related EBITDA. These factors impacted our ability to comply with our debt covenants under the Senior Credit Agreement by reducing our production, reserves and EBITDA on a current and a pro forma historical basis. Over the short term, our strategy makes us more susceptible to fluctuations in performance and compliance with these covenants more challenging. In addition, we have faced certain operational challenges that have impacted our ability to comply, including recently, elevated levels of H2S in the natural gas produced from our Monument Draw wells and severance payments associated with personnel changes. Over the longer term, we expect that our strategy and our investments will result in increased production and reserves, lower lease operating costs and more abundant drilling opportunities.

Changes in the level and timing of our production, drilling and completion costs, the cost and availability of transportation for our production and other factors varying from our expectations can cause our EBITDA to change significantly, particularly in those quarters where it is annualized, and affect our ability to comply with the covenants under our Senior Credit Agreement. These amendments and consents were intended to provide us with the covenant relief we believe is adequate under our currently projected business plan; however, as stated previously, even relatively modest variations from the assumptions underlying our business plan may cause significant changes to our EBITDA and/or our debt level, which could cause us to fall out of compliance with our covenants. As a consequence, we constantly anticipate and identify potential covenant compliance issues and work with the lenders under our Senior Credit Agreement to address any such issues ahead of time. While we have been successful to date in obtaining modifications of our covenants as needed, there can be no assurance that we will be successful in the future.

Additionally, the indenture governing our senior debt contains covenants limiting our ability to incur indebtedness unless we meet one of two alternative tests or utilize the limited exceptions available. The first test applies to all indebtedness and requires that, after giving effect to the incurrence of additional debt, our fixed charge coverage ratio (which is the ratio of our adjusted consolidated EBITDA (as defined in our indenture) to our adjusted consolidated interest expense over the trailing four fiscal quarters) will be at least 2.00:1.00. The second test allows us to incur additional indebtedness, beyond the limitations of the fixed charge coverage ratio test, as long as this additional debt is incurred under Credit Facilities (as defined in our indenture) and generally, the amount thereof is not more than, subject to certain exceptions, the greater of (i) $350 million, (ii) the borrowing base in effect under our Senior Credit Agreement, and (iii) 30% of our adjusted consolidated net tangible assets, or ACNTA. ACNTA is defined in our indenture and is determined primarily by the value of discounted future net revenues from proved oil and natural gas reserves plus the capitalized cost attributable to our unevaluated properties. As of December 31, 2018, we were permitted to incur additional indebtedness under the indenture, but may be limited in the future. Lower oil and natural gas prices, among other factors, could reduce our adjusted consolidated EBITDA, as well as our ACNTA, and thus could reduce our ability to incur additional indebtedness.

Our future capital resources and liquidity depend, in part, on our success in developing our leasehold interests, growing our reserves and production and finding additional reserves. Cash is required to fund capital expenditures necessary to offset inherent declines in our production and proven reserves, which is typical in the capital-intensive oil and natural gas industry. We therefore continuously monitor our liquidity and the capital markets and evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources, and drilling successes.

We strive to maintain financial flexibility while pursuing our drilling plans and may continue to access capital markets (if available on acceptable terms) as necessary to, among other things, maintain adequate borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects while sustaining sufficient operating cash levels. Our ability to complete future debt and equity offerings and maintain or increase our borrowing base under our Senior Credit Facility is subject to a number of variables, including our level of oil and natural gas production, proved reserves and commodity prices, the amount and cost of our other indebtedness, as well as various economic and market conditions that have historically affected the oil and natural gas industry. Even if we are otherwise successful in growing our proved reserves and production, if oil and natural gas prices decline for a sustained period of time, our ability to fund our capital expenditures, complete acquisitions, reduce debt, meet our financial obligations and become profitable may be materially impacted.

We are actively considering alternative financing arrangements that may provide greater financial flexibility than our current Senior Credit Agreement. While we believe there are benefits to these alternatives in terms of limiting risk and uncertainty, they generally come at the expense of increased cost, at least over the near-term, so we are carefully weighing these alternatives and benefits against near-term costs. There can be no assurance that we pursue one of these alternatives or that they continue to be available to us. In the event that we are unable to access sufficient capital to fund our business and planned capital expenditures, we may be required to curtail our drilling, development, land acquisitions and other activities, which could result in a decrease in our production of oil and natural gas, subject us to forfeitures of leasehold interests to the extent we are unable or unwilling to renew them, and force us to sell some of our assets on an untimely or unfavorable basis, each of which could adversely affect our results of operations and financial condition.

We are exposed to various risks including energy commodity price risk. When oil, natural gas, and natural gas liquids prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. While we use derivative instruments to provide partial protection against declines in oil and natural gas prices, the total volumes we hedge varies from period to period based on our view of current and future market conditions. Our hedge policies and objectives may change significantly as our operational profile changes and/or commodities prices change. We do not enter into derivative contracts for speculative trading purposes.

Cash Flow

In 2018, our primary sources of cash and cash equivalents were from operating and financing activities. Cash generated by financing activities and proceeds from the sale of the Water Assets were used to fund the acquisitions of the Northern Tract of the Ward County Assets and the West Quito

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Draw Properties, as well as our drilling and completion program. See "*Results of Operations*" for a review of the impact of prices and volumes on operating revenues.

Net increase (decrease) in cash and cash equivalents is summarized as follows (in thousands):

	Successor			Predecessor
	Years Ended December 31,		Period from September 10, 2016 through December 31, 2016	Period from January 1, 2016 through September 9, 2016
	2018	2017		
Cash flows provided by (used in) operating activities	$ 67,155	$ 114,591	$ 103,136	$ 175,348
Cash flows provided by (used in) investing activities	(706,485)	598,592	(63,042)	(227,774)
Cash flows provided by (used in) financing activities	262,125	(289,136)	(54,013)	58,343
Net increase (decrease) in cash and cash equivalents	$ (377,205)	$ 424,047	$ (13,919)	$ 5,917

Operating Activities. Net cash flows provided by operating activities were $67.2 million and $114.6 million for the years ended December 31, 2018 and 2017, respectively. Net cash provided by operating activities for the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016 were $103.1 million and $175.3 million, respectively. Key drivers of net operating cash flows are commodity prices, production volumes, operating costs, and in 2016, realized settlements on our derivative contracts.

Operating cash flows for the year ended December 31, 2018 decreased from prior year primarily due to our divestitures in 2017, in which we divested non-core producing properties in other areas for primarily undeveloped acreage in the Delaware Basin. This decrease was partially offset by $35.2 million of proceeds primarily related to hedge monetizations that occurred during the year.

The $114.6 million of operating cash flows for the year ended December 31, 2017 were lower than the prior year primarily due to a decrease in realized settlements. Realized settlements on derivative contracts decreased $312.7 million over the prior year period. Our oil and natural gas revenues also decreased approximately $42.2 million over the prior year period due to a decrease in our average daily production. Average realized prices (excluding the effects of hedging arrangements) were $37.58 per Boe, $35.87 per Boe and $28.53 per Boe for the year ended December 31, 2017, for the period September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively.

For the period September 10, 2016 through December 31, 2016, cash flows were modestly impacted by changes in our working capital. For the period January 1, 2016 through September 9, 2016 our net operating cash flows were $175.3 million, which resulted primarily from realized settlements on our derivative contracts that were partially offset by transaction costs related to our chapter 11 bankruptcy and reorganization activities.

Investing Activities. Net cash flows used in investing activities for the year ended December 31, 2018 were approximately $706.5 million. Net cash flows provided by investing activities for the year ended December 31, 2017 were approximately $598.6 million. Net cash used in investing activities for the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016 were $63.0 million and $227.8 million, respectively.

In 2018, we incurred cash expenditures of $333.9 million on acquisition activities, the majority of which related to the acquisitions of the West Quito Draw Properties and the Northern Tract of the Ward County Assets. Additionally, we spent $475.7 million on oil and natural gas capital expenditures, of which $444.4 million related to drilling and completion costs. We also spent approximately $117.0 million on capital expenditures related to our other operating property and equipment, primarily to develop our water recycling facilities and gas gathering and treating infrastructure. These cash outflows were offset by proceeds from the sale of our Water Assets of $213.8 million.

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In 2017, we incurred cash expenditures of $700.1 million to acquire acreage and related assets in the Hackberry Draw area of the Delaware Basin located in Pecos and Reeves Counties, Texas (collectively, the Pecos County Assets) of which $674.6 million related to the oil and natural gas properties and $25.5 million related to the other operating property and equipment. In addition to the acquisition of the Pecos County Assets, we spent approximately $344.0 million on other acquisitions, primarily in the Delaware Basin to increase our position in the area. We spent $331.3 million on oil and natural gas capital expenditures, of which $309.6 million related to drilling and completion costs. These cash outflows for acquisitions and our drilling and completion activities were more than offset by cash inflows from our non-core asset sales. Approximately $1.39 billion of the proceeds from the sale of all of our operated oil and natural gas leases, oil and natural gas wells and related assets located in the Williston Basin in North Dakota (the Williston Divestiture) were allocated to the oil and natural gas properties divested and $10.9 million of the proceeds were allocated to the other operating property and equipment divested. Proceeds from the sale of all of our oil and natural gas properties and related assets located in the Eagle Ford formation of East Texas (the El Halcón Divestiture) were $494.3 million of which $484.1 million related to the oil and natural gas properties divested and $10.2 million related to the other operating property and equipment divested. In November 2017, proceeds from the sale of our non-operated oil and natural gas properties and related assets located in the Williston Basin in North Dakota and Montana (the Non-Operated Williston Assets) totaled approximately $105.2 million.

During the period of September 10, 2016 through December 31, 2016, we spent $61.4 million on oil and natural gas capital expenditures, of which $54.4 million related to drilling and completion costs. During the period of January 1, 2016 through September 9, 2016, we spent $226.7 million on oil and natural gas capital expenditures, of which $129.5 million related to drilling and completion costs and the remainder was primarily associated with capitalized interest, and to a lesser extent, leasing and seismic data.

Financing Activities. Net cash flows provided by financing activities for the year ended December 31, 2018 were approximately $262.1 million. Net cash flows used in financing activities for the year ended December 31, 2017 were $289.1 million. Net cash flows used in financing activities for the period of September 10, 2016 through December 31, 2016 were $54.0 million and net cash flows provided by financing activities for the period of January 1, 2016 through September 9, 2016 were $58.3 million.

In 2018, we issued an additional $200.0 million aggregate principal amount of our 6.75% senior notes due 2025. Proceeds from the private placement were approximately $202.4 million after initial purchasers' premiums and deducting commissions and offering expenses. Additionally, we sold 9.2 million shares of common stock in a public offering at a price of $6.90 per share. The net proceeds from the offering were approximately $60.4 million after deducting underwriters' discounts and offering expenses.

In 2017, we issued $850.0 million aggregate principal amount of our new 6.75% senior notes due 2025. Proceeds from the private placement were approximately $834.1 million after deducting initial purchasers' discounts and commissions and offering expenses. We utilized the majority of the net proceeds from the private placement to fund the repurchase and redemption of the then outstanding 8.625% senior secured second lien notes due 2020 (the 2020 Second Lien Notes). The net cash to make these repurchases and redemptions was approximately $736.8 million and we recognized a loss on the extinguishment of debt, representing a $30.9 million loss on the repurchase for the tender premium paid and a $26.0 million loss on the write-off of the discount on the notes. During 2017, we also utilized a portion of the proceeds from the Williston Divestiture to repay borrowings outstanding under our Senior Credit Agreement, repurchase approximately $425.0 million principal amount of our 2025 Notes and redeem all of our then outstanding 12.0% senior secured second lien notes due 2022 (the 2022 Second Lien Notes). The net cash used to make the repurchase of the 2025 Notes was

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approximately $437.8 million and we recognized a loss on the extinguishment of debt, representing a $12.8 million loss on the repurchase for the tender premium paid, an $8.3 million loss on the write-off of the discount on the notes, and a $7.8 million loss on the write-off of the debt issuances costs on the notes. The net cash used to make the redemption of the 2022 Second Lien Notes was approximately $137.8 million and we recognized a loss on the extinguishment of debt, representing a $23.0 million loss on the redemption for the make whole premium paid and a $6.2 million loss on the write-off of the discount on the notes. We also paid a consent fee of approximately $16.9 million to the holders of our 2025 Notes. Additionally, we issued 5,518 shares of preferred stock at $72,500 per share. Gross proceeds from this issuance were approximately $400.1 million.

During the period of September 10, 2016 through December 31, 2016, we paid a consent fee of approximately $10.0 million to holders of our Second Lien Notes and made net repayments of $44.0 million on our Senior Credit Agreement. The primary drivers of cash provided by financing activities for the period of January 1, 2016 through September 9, 2016 were net borrowings on our Predecessor credit agreement, offset by cash payments totaling $97.5 million made to the Third Lien Noteholders, Unsecured Noteholders, Convertible Noteholder and Preferred Holders in accordance with the Plan.

During the first quarter of 2016, we repurchased approximately $24.5 million principal amount of our 9.75% senior notes due 2020, $51.8 million principal amount of our 8.875% senior notes due 2021, and $15.5 million principal amount of our 9.25% senior notes due 2022. The net cash used to make these repurchases was approximately $9.7 million and we recognized an $81.4 million net gain on the extinguishment of debt, as an $82.1 million gain on the repurchase was partially offset by the write-down of $0.7 million associated with related issuance costs and discounts and premiums for the respective senior notes. Upon settlement of the repurchases, we paid all accrued and unpaid interest since the respective interest payment dates of the senior notes repurchased.

Contractual Obligations

We have a significant degree of flexibility to adjust the level of our future capital expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, developmental and exploration activities, oil and natural gas price conditions, our access to capital and liquidity and other related economic factors. We currently have no material off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities. The following table summarizes our contractual obligations and commitments by payment periods as of December 31, 2018.

		Payments Due by Period			
Contractual Obligations	**Total**	**2019**	**2020 - 2021**	**2022 - 2023**	**2024 and Beyond**[4]
			(In thousands)		
Senior revolving credit facility	$	$	$	$	$
6.75% senior notes due 2025[1]	625,005				625,005
Interest expense on long-term debt[2]	262,394	43,558	87,116	84,376	47,344
Operating leases	10,607	3,792	4,249	1,967	599
Drilling rig commitments[3]	4,973	4,973			
Rig stacking commitments	3,781	781	3,000		
Purchase commitments	20,233	20,233			
Total contractual obligations	$ 926,993	$ 73,337	$ 94,365	$ 86,343	$ 672,948

(1) *Excludes a $7.2 million unamortized discount, a $5.4 million unamortized premium, and $10.1 million unamortized debt issuance costs as of December 31, 2018.*

(2) *Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2018 less required annual repayments.*

(3) *Early termination of our drilling rig commitments would result in termination penalties approximating $4.7 million, which would be in lieu of paying the remaining active commitments of approximately $5.0 million.*

We lease corporate office space in Houston, Texas and Denver, Colorado. Rent expense was approximately $3.7 million and $3.9 million for the years ended December 31, 2018 and 2017, respectively. Rent expense was approximately $1.4 million for the period of September 10, 2016 through December 31, 2016 and $5.9 million for the period January 1, 2016 through September 9, 2016. Future obligations associated with our operating leases are presented in the table above.

We also have various long-term gathering, transportation and sales contracts with respect to production from the Delaware Basin. As of December 31, 2018, we had in place three long-term crude oil contracts and ten long-term natural gas contracts in this area, with sales prices based on posted market rates. Under the terms of these contracts we have committed a substantial portion of our production from this area for periods ranging from one to twenty years from the date of first production.

The contractual obligations table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations. In addition, amounts related to our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total estimated amount of our asset retirement obligations at December 31, 2018 was $6.9 million.

Senior Revolving Credit Facility

On September 7, 2017, we entered into the Senior Credit Agreement by and among us, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders. Pursuant to the Senior Credit Agreement, the lenders party thereto agreed to provide us with a $1.0 billion senior secured reserve-based revolving credit facility with a current borrowing base of $275.0 million. The maturity date of the Senior Credit Agreement is September 7, 2022. The borrowing base will be redetermined semi-annually, with the lenders and us each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the estimated value of our oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 1.25% to 2.25% for ABR-based loans or at specified margins over LIBOR of 2.25% to 3.25% for Eurodollar-based loans. These margins fluctuate based on the utilization of the facility. We may elect, at our option, to prepay any borrowings outstanding under the Senior Credit Agreement without premium or penalty (except with respect to any break funding payments which may be payable pursuant to the terms of the Senior Credit Agreement). Amounts outstanding under the Senior Credit Agreement are guaranteed by certain of our direct and indirect subsidiaries and secured by a security interest in substantially all of our assets and the assets of our subsidiaries.

The Senior Credit Agreement also contains certain financial covenants, including the maintenance of (i) a Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement), which was recently revised by the H2S Consent, Severance and Office Payments Consent and Seventh Amendment, as discussed below, and (ii) a Current Ratio (as defined in the Senior Credit Agreement) not to be less than 1.00:1.00. After giving effect to the H2S Consent and the Fifth Amendment (both of which are discussed further below), at December 31, 2018, we were in compliance with the financial covenants under the Senior Credit Agreement.

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The Senior Credit Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

At December 31, 2018, we had no indebtedness outstanding, approximately $1.0 million letters of credit outstanding and approximately $274.0 million of borrowing capacity available under the Senior Credit Agreement.

On February 28, 2019, the lenders party to our Senior Credit Agreement issued the Severance and Office Payments Consent to us whereby Severance Payments and Office Payments (as defined in the Severance and Office Payments Consent) may exceed the maximum level allowed for adding back non-recurring expenses and charges in the definition of EBITDA (as defined in the Senior Credit Agreement) when calculating the ratio of Consolidated Total Net Debt to EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarter ending March 31, 2019.

On February 15, 2019, we entered into the Seventh Amendment to the Senior Credit Agreement which, among other things, provides for (i) the use of annualized financial data in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending March 31, 2019, June 30, 2019 and September 30, 2019 and (ii) amends the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA to be (a) 5.00 to 1.0 for the fiscal quarter ending March 31, 2019, (b) 4.75 to 1.0 for the fiscal quarter ending June 30, 2019, (c) 4.5 to 1.0 for the fiscal quarter ending September 30, 2019, (d) 4.25 to 1.0 for the fiscal quarter ending December 31, 2019, and (e) 4.0 to 1.0 for the fiscal quarter ending March 31, 2020 and any fiscal quarter thereafter.

On November 16, 2018, we entered into the Sixth Amendment to the Senior Credit Agreement, which, among other things, provided for (i) provisions allowing for optional increases in the maximum Credit Amount (as defined in the Senior Credit Agreement) by us and the lenders party thereto. The Sixth Amendment also established the borrowing base at $350.0 million following the closing of the sale of the Water Assets; however, we and the lenders agreed to reduce the Aggregate Maximum Credit Amounts (as defined in the Senior Credit Agreement) to $275.0 million, thereby effectively limiting the amount available to borrow under the Senior Credit Agreement to $275.0 million.

On November 7, 2018, we entered into the Fifth Amendment to the Senior Credit Agreement which, among other things, provided for (i) the use of annualized financial data in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending September 30, 2018, December 31, 2018, March 31, 2019, June 30, 2019 and September 30, 2019 and (ii) amended the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA of (a) 4.75 to 1.0 for the fiscal quarter ending September 30, 2018, (b) 4.25 to 1.0 for the fiscal quarter ending December 31, 2018 and (c) 4.0 to 1.0 for the fiscal quarter ending March 31, 2019 and any fiscal quarter thereafter.

On November 6, 2018, the lenders party to our Senior Credit Agreement issued the H2S Consent to us whereby H2S Expenses (as defined in the H2S Consent) may exceed the maximum level allowed for adding back non-recurring expenses and charges in the definition of EBITDA (as defined in the Senior Credit Agreement) when calculating the ratio of Consolidated Total Net Debt to EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending September 30, 2018, December 31, 2018 and March 31, 2019.

On July 12, 2018, we entered into the Fourth Amendment to the Senior Credit Agreement which provided for an increase in the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA (as defined in the Senior Credit Agreement) of (i) 4.75 to 1.0 for the fiscal quarter ending September 30, 2018, (ii) 5.0 to 1.0 for the fiscal quarters ending December 31, 2018, March 31, 2019 and June 30, 2019, (iii) 4.25 to 1.0 for the fiscal quarter ending September 30, 2019

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and (iv) 4.0 to 1.0 for the fiscal quarter ending December 31, 2019 and any fiscal quarter thereafter; provided, however, that if we consummated a sale of all or a material portion of our midstream assets, then the ratio of Consolidated Total Net Debt to EBITDA would be reduced to 4.0 to 1.0 for each fiscal quarter ending after the fiscal quarter in which such sale was consummated.

On May 1, 2018, we entered into the Third Amendment to the Senior Credit Agreement which provided for an assignment and reallocation of the Maximum Credit Amounts (as defined in the Senior Credit Agreement) among certain of the lender financial institutions. The Third Amendment did not adjust the aggregate Maximum Credit Amounts, which remained at $1.0 billion.

On February 2, 2018, we entered into the Second Amendment to the Senior Credit Agreement (as amended, the Senior Credit Agreement) by and among us, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders. For certain fiscal quarters in 2018, the Second Amendment, among other things, provided flexibility with respect to certain financial covenants as specified in the Senior Credit Agreement. The Second Amendment provides for (i) the use of annualized financial information in determining EBITDA (as defined in the Senior Credit Agreement) for the fiscal quarters ending June 30, 2018, September 30, 2018 and December 31, 2018, (ii) an increase in the ratio of Consolidated Total Net Debt (as defined in the Senior Credit Agreement) to EBITDA of 4.50:1.00 for the fiscal quarter ending June 30, 2018, and a ratio of 4.00:1.00 for any fiscal quarter thereafter, (iii) a waiver of compliance with the covenant relating to the Total Net Indebtedness Leverage Ratio (as defined in the Senior Credit Agreement) for the fiscal quarter ending March 31, 2018, and (iv) a waiver of the automatic reduction to the borrowing base that would have otherwise resulted due to the issuance of the Additional 2025 Notes, which is discussed further below.

6.75% Senior Notes

On February 16, 2017, we issued $850.0 million aggregate principal amount of our 2025 Notes in a private placement exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as amended (Securities Act), Rule 144A and Regulation S, and applicable state securities laws. The 2025 Notes were issued at par and bear interest at a rate of 6.75% per annum, payable semi-annually on February 15 and August 15 of each year. The 2025 Notes will mature on February 15, 2025. Proceeds from the private placement were approximately $834.1 million after deducting initial purchasers' discounts and commissions and offering expenses. We used a portion of the net proceeds from the private placement to fund the repurchase and redemption of the outstanding 2020 Second Lien Notes and for general corporate purposes.

The 2025 Notes are governed by an Indenture, dated as of February 16, 2017 (as supplemented, the February 2017 Indenture) by and among us, the Guarantors and U.S. Bank National Association, as Trustee, which contains affirmative and negative covenants that, among other things, limit the ability of us and the Guarantors to incur indebtedness; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; refinance certain indebtedness; merge with or into other companies or transfer substantially all of their assets; and, in certain circumstances, to pay dividends or make other distributions on stock. The February 2017 Indenture also contains customary events of default. Upon the occurrence of certain events of default, the Trustee or the holders of the 2025 Notes may declare all outstanding 2025 Notes to be due and payable immediately. The 2025 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by our existing wholly-owned subsidiaries. We have no material independent assets or operations apart from the assets and operations of our subsidiaries.

In connection with the sale of the 2025 Notes, on February 16, 2017, we, the Guarantors and J.P. Morgan Securities LLC, on behalf of itself and as representative of the initial purchasers, entered into a Registration Rights Agreement (the 2017 Registration Rights Agreement) pursuant to which we agreed to, among other things, use reasonable best efforts to file a registration statement under the Securities Act and complete an exchange offer for the 2025 Notes within 365 days after closing. We completed the exchange offer for the 2025 Notes on February 1, 2018.

On July 25, 2017, we concluded a consent solicitation of the holders of the 2025 Notes (the Consent Solicitation) and obtained consents to amend the February 2017 Indenture from approximately 99% of the holders of the 2025 Notes. As supplemented, the February 2017 Indenture amends provisions in order to exempt, among other things, the Williston Divestiture from certain provisions therein triggered upon a sale of "all or substantially all of the assets" of ours. Consenting holders of the 2025 Notes received a consent fee of 2.0% of principal, or $16.9 million. We recorded the $16.9 million consent fees paid as a discount on the 2025 Notes.

On September 7, 2017, we commenced an offer to purchase for cash up to $425.0 million of the $850.0 million outstanding aggregate principal amount of our 2025 Notes at 103.0% of principal plus accrued and unpaid interest. The consummation of the Williston Divestiture constituted a "Williston Sale" under the February 2017 Indenture, and we were required to make an offer to all holders of the 2025 Notes to purchase for cash an aggregate principal amount up to $425.0 million of the 2025 Notes. The offer to purchase expired on October 6, 2017, with notes representing in excess of $425.0 million of principal amount validly tendered. As a result, on October 10, 2017, we repurchased approximately $425.0 million principal amount of the 2025 Notes on a pro rata basis at 103.0% of par plus accrued and unpaid interest of approximately $4.1 million.

We recognized a loss on the extinguishment of debt, representing a $12.8 million loss on the redemption for the tender premium paid, a $8.3 million loss on the write-off of the discount, and a $7.8 million loss on the write-off of debt issuance costs on the notes. The loss was recorded in "*Gain (loss) on extinguishment of debt"* on the consolidated statements of operations.

On February 15, 2018, we issued an additional $200.0 million aggregate principal amount of our 2025 Notes at a price to the initial purchasers of 103.0% of par. The net proceeds from the sale of the Additional 2025 Notes were approximately $202.4 million after deducting initial purchasers' premiums, commissions and estimated offering expenses and were used to fund the cash consideration for the acquisition of the West Quito Draw Properties and for general corporate purposes, including funding our 2018 drilling program. These notes were issued under the February 2017 Indenture.

The Additional 2025 Notes are treated as a single class with, and have the same terms as, the 2025 Notes, except that the Additional 2025 Notes will initially be subject to transfer restrictions and have the benefit of certain registration rights and provisions for the payment of additional interest in the event of a breach with respect to such registration rights pursuant to the terms of a Registration Rights Agreement, entered into on February 15, 2018 (the 2018 Registration Rights Agreement). Pursuant to the 2018 Registration Rights Agreement we agreed to, among other things, use reasonable best efforts to file a registration statement under the Securities Act and complete an exchange offer for the 2025 Notes within 180 days after closing. We completed the exchange offer for the Additional 2025 Notes on May 17, 2018.

The remaining unamortized discount on the 2025 Notes was $7.2 million at December 31, 2018. The unamortized premium on the Additional 2025 Notes was $5.4 million at December 31, 2018.

Off-Balance Sheet Arrangements

At December 31, 2018, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of additional accounting policies and estimates made by management.

Fresh-start Accounting

Upon our emergence from chapter 11 bankruptcy, on September 9, 2016, we adopted fresh-start accounting in accordance with the provisions set forth in ASC 852, *Reorganizations,* as (i) the Reorganization Value of our assets immediately prior to the date of confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of our existing voting shares of the Predecessor entity received less than 50% of the voting shares of the emerging entity. Adopting fresh-start accounting results in a new financial reporting entity with no beginning or ending retained earnings or deficit balances. Upon the adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the fresh-start reporting date.

Fresh-start accounting requires an entity to present its assets, liabilities, and equity as if it were a new entity upon emergence from bankruptcy. The new entity is referred to as "Successor" or "Successor Company." However, we will continue to present financial information for any periods before adoption of fresh-start accounting for the Predecessor Company. The Predecessor and Successor companies may lack comparability, as required in ASC Topic 205, *Presentation of Financial Statements* (ASC 205). ASC 205 states financial statements are required to be presented comparably from year to year, with any exceptions to comparability clearly disclosed. Therefore, "black-line" financial statements are presented to distinguish between the Predecessor and Successor Companies. Refer to Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 3,"*Fresh-start Accounting,"* for further details.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using the unweighted arithmetic average of the first day of the month

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for each of the 12-month prices for oil and natural gas within the period, holding prices and costs constant and applying a 10% discount rate.

Full Cost Method

We use the full cost method of accounting for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized into a cost center (the amortization base or full cost pool). Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. All general and administrative costs unrelated to drilling activities are expensed as incurred. The capitalized costs of our evaluated oil and natural gas properties, plus an estimate of our future development and abandonment costs are amortized on a unit-of-production method based on our estimate of total proved reserves. Our financial position and results of operations could have been significantly different had we used the successful efforts method of accounting for our oil and natural gas activities.

Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and SEC guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depletion, depreciation and accretion expense and the full cost ceiling test limitation. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under defined economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

Our estimated proved reserves for the years ended December 31, 2018, 2017 and 2016 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. *Consolidated Financial Statements and Supplementary Data "Supplemental Oil and Gas Information (Unaudited).*"

Depletion Expense

Our rate of recording depletion expense is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record depletion expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. At December 31, 2018, a five percent positive revision to proved reserves would decrease the depletion rate by approximately $0.67 per Boe and a five percent negative revision to proved reserves would increase the depletion rate by approximately $0.75 per Boe.

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Full Cost Ceiling Test Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and could result in lower amortization expense in future periods. The present value of our estimated proved reserves (discounted at 10%) is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our oil and natural gas properties could occur in the future.

If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2018 had been 10% lower while all other factors remained constant, our ceiling amount related to our net book value of oil and natural gas properties would have been reduced by approximately $193.9 million and would have generated a full cost ceiling impairment.

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production facilities, gathering systems and related structures and restoration costs. We develop estimates of these costs for each of our properties based upon their geographic location, type of production facility, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. At December 31, 2018, a five percent increase in future development and abandonment costs would increase the depletion rate by approximately $0.24 per Boe and a five percent decrease in future development and abandonment costs would decrease the depletion rate by $0.23 per Boe.

Accounting for Derivative Instruments and Hedging Activities

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging* (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, when derivative contracts are available at terms (or prices) acceptable to us, we may hedge a portion of our forecasted oil, natural gas, and natural gas liquids production. Derivative contracts entered into by us have consisted of transactions in which we hedge the variability of cash flow related to a forecasted transaction. We elected to not designate any of our positions for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

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Income Taxes

Our provision for taxes includes both state and federal taxes. We account for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. We classify all deferred tax assets and liabilities, along with any related valuation allowance, as noncurrent on the consolidated balance sheets.

In assessing the need for a valuation allowance on our deferred tax assets, we consider possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies. We consider all available evidence (both positive and negative) in determining whether a valuation allowance is required. Based upon the evaluation of available evidence we recorded a decrease of $136.4 million to our valuation allowance in connection with writing off certain deferred tax assets for net operating loss carryforwards that are expected to expire unutilized as a result of the ownership change during 2018. A valuation allowance of $290.3 million has been applied against our deferred tax assets as of December 31, 2018.

We follow ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the financial statements. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows. The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

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Comparison of Results of Operations

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

We reported net income of $46.0 million for the year ended December 31, 2018 compared to net income of $535.7 million for the comparable period in 2017. The following table summarizes key items of comparison and their related change for the periods indicated.

	Years Ended December 31,		
In thousands (except per unit and per Boe amounts)	**2018**	**2017**	**Change**
Net income (loss)	$ 45,959	$ 535,686	$ (489,727)
Operating revenues:			
Oil	199,601	340,674	(141,073)
Natural gas	6,791	16,194	(9,403)
Natural gas liquids	19,137	18,969	168
Other	1,080	2,128	(1,048)
Operating expenses:			
Production:			
Lease operating	25,075	61,743	(36,668)
Workover and other	8,574	21,739	(13,165)
Taxes other than income	12,787	30,757	(17,970)
Gathering and other	60,090	40,783	19,307
Restructuring	128	7,535	(7,407)
General and administrative:			
General and administrative	46,790	74,594	(27,804)
Stock-based compensation	15,266	36,757	(21,491)
Depletion, depreciation and accretion:			
Depletion Full cost	69,796	104,306	(34,510)
Depreciation Other	7,402	4,595	2,807
Accretion expense	329	1,306	(977)
(Gain) loss on sale of oil and natural gas properties	7,235	(721,573)	728,808
(Gain) loss on sale of Water Assets	(119,003)		(119,003)
Other income (expenses):			
Net gain (loss) on derivative contracts	92,625	1,291	91,334
Interest expense and other, net	(43,015)	(71,097)	28,082
Gain (loss) on extinguishment of debt		(114,931)	114,931
Income tax benefit (provision)	(95,791)	5,000	(100,791)
Production:			
Crude oil MBbls	3,558	7,511	(3,953)
Natural gas MMcf	4,607	7,439	(2,832)
Natural gas liquids MBbls	749	1,249	(500)
Total MBoe(1)	5,075	10,000	(4,925)
Average daily production Boe(1)	13,904	27,397	(13,493)
Average price per unit(2):			
Crude oil price Bbl	$ 56.10	$ 45.36	$ 10.74
Natural gas price Mcf	1.47	2.18	(0.71)
Natural gas liquids price Bbl	25.55	15.19	10.36
Total per Boe(1)	44.44	37.58	6.86
Average cost per Boe:			
Production:			
Lease operating	$ 4.94	$ 6.17	$ (1.23)
Workover and other	1.69	2.17	(0.48)
Taxes other than income	2.52	3.08	(0.56)
Gathering and other	11.84	4.08	7.76
Restructuring	0.03	0.75	(0.72)
General and administrative:			
General and administrative	9.22	7.46	1.76
Stock-based compensation	3.01	3.68	(0.67)
Depletion	13.75	10.43	3.32

(1)

Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2) *Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.*

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Oil, natural gas and natural gas liquids revenues were $225.5 million and $375.8 million for the years ended December 31, 2018 and 2017, respectively. For the years ended December 31, 2018 and 2017, production averaged 13,904 Boe/d and 27,397 Boe/d, respectively. Our average daily oil and natural gas production decreased in 2018 when compared to the prior year due to our divestitures during 2017. This decrease was partially mitigated by the production associated with our Delaware Basin assets and our drilling activities since acquiring the assets. Average realized prices (excluding the effects of hedging arrangements) were $44.44 per Boe and $37.58 per Boe for the years ended December 31, 2018 and 2017, respectively. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, transportation take-away capacity constraints, inventory storage levels, basis differentials and other factors.

Lease operating expenses were $25.1 million and $61.7 million for the years ended December 31, 2018 and 2017, respectively. On a per unit basis, lease operating expenses were $4.94 per Boe and $6.17 per Boe for the years ended December 31, 2018 and 2017, respectively. The decrease in lease operating expenses from 2017 levels is primarily attributed to our El Halcón and Williston Divestitures in 2017 which greatly reduced our inventory of producing wells.

Workover and other expenses were $8.6 million and $21.7 million for the years ended December 31, 2018 and 2017, respectively. On a per unit basis, workover and other expenses were $1.69 per Boe and $2.17 per Boe for the years ended December 31, 2018 and 2017, respectively. The decrease in workover and other expenses from 2017 levels is primarily attributed to our El Halcón and Williston Divestitures in 2017 which greatly reduced our inventory of producing wells.

Taxes other than income were $12.8 million and $30.8 million for the years ended December 31, 2018 and 2017, respectively. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease. On a per unit basis, taxes other than income were $2.52 per Boe and $3.08 per Boe for the years ended December 31, 2018 and 2017, respectively.

Gathering and other expenses were $60.1 million and $40.8 million for the years ended December 31, 2018 and 2017, respectively. Gathering and other expenses include gathering fees paid on our oil and natural gas production, operating expenses on our water recycling facilities and gas gathering infrastructure, gas treating fees, rig stacking charges and other. Approximately $7.3 million and $26.3 million for the years ended December 31, 2018 and 2017, respectively, relate to gathering and marketing fees paid on our oil and natural gas production. Approximately $51.8 million and $7.6 million expenses for the years ended December 31, 2018 and 2017, respectively, relate to operating expenses on our water recycling facilities and gas gathering infrastructure. Included in 2018 is approximately $32.5 million of costs to remove hydrogen sulfide from natural gas produced from our Monument Draw properties as a consequence of a third party pipeline temporarily going out of service. We have secured capacity on another third party pipeline for a portion of the natural gas produced in this area and are progressing on solutions for the remaining natural gas produced, including the installation of treating equipment which will alleviate reliance upon third party services for the removal of hydrogen sulfide from the natural gas produced. We expect these treating costs to decrease substantially in early 2019. Also included are $1.9 million and $6.8 million of rig stacking charges for the years ended December 31, 2018 and 2017, respectively.

Restructuring expense was approximately $0.1 million and $7.5 million for the years ended December 31, 2018 and 2017, respectively. This represents severance costs and accelerated stock-based compensation expense related to the termination of certain employees in conjunction with our divestitures.

General and administrative expense was $46.8 million and $74.6 million for the years ended December 31, 2018 and 2017, respectively. General and administrative expense decreased in the current period due to a reduction in our workforce. In the prior year period, we also incurred approximately $8.4 million of transaction costs paid in conjunction with the Williston Divestiture. On a per unit basis, general and administrative expenses were $9.22 per Boe and $7.46 per Boe for the years ended December 31, 2018 and 2017, respectively. General and administrative expense on a per unit basis increased in the current period due to a decrease in our average daily production primarily as a result of our 2017 divestitures.

Stock-based compensation expense was $15.3 million and $36.8 million for the years ended December 31, 2018 and 2017, respectively. Stock-based compensation expense decreased in the current period due to a reduction in our workforce and restricted stock granted in connection with our emergence from chapter 11 bankruptcy which vested on or before September 30, 2017.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. Depletion expense was $69.8 million and $104.3 million for the years ended December 31, 2018 and 2017, respectively. On a per unit basis, depletion expense was $13.75 per Boe and $10.43 per Boe for the years ended December 31, 2018 and 2017, respectively. The increase in depletion rate per Boe from 2017 levels is primarily attributable to our shift in operations to the Delaware Basin.

Under the full cost method of accounting, sales of oil and gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless the adjustment significantly alters the relationship between capitalized costs and estimated proved reserves. If the El Halcón and Williston Divestitures were accounted for as an adjustment of capitalized costs with no gain or loss recognized, the adjustment would have significantly altered the relationship between capitalized costs and estimated proved reserves. Accordingly, we recognized a gain on the sale of the oil and natural gas properties associated with the El Halcón Divestiture of $235.7 million for the year ended December 31, 2017. We also recognized an initial gain on the sale of the Williston Divestiture of $485.9 million for the year ended December 31, 2017. We reduced the gain on the sale of oil and natural gas properties associated with the Williston Divestiture by approximately $7.2 million for the year ended December 31, 2018, as the result of customary post-closing adjustments. The carrying value of the properties sold was determined by allocating total capitalized costs within the full cost pool between properties sold and properties retained based on their relative fair values.

On December 20, 2018, we sold our water infrastructure assets located in the Delaware Basin for a total adjusted purchase price of $214.1 million and we recognized a $119.0 million gain on the sale.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil, natural gas and natural gas liquids production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2018, we had a $69.7 million derivative asset, $57.3 million of which was classified as current, and we had a $12.9 million derivative liability, $3.8 million of which was classified as current. We recorded a net derivative gain of $92.6 million ($84.3 million net unrealized gain and $8.3 million net realized gain on settled and early terminated contracts) for the year ended December 31, 2018 compared to a net derivative gain of $1.3 million ($16.5 million net unrealized loss and $17.8 million net realized gain on settled contracts) in the same period in 2017.

Interest expense and other was $43.0 million and $71.1 million for the years ended December 31, 2018 and 2017, respectively. We utilized a portion of the proceeds from our divestitures in 2017 to repurchase outstanding long-term debt, which drove a decrease in interest expense in the year ended

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December 31, 2018 when compared to the same period in the prior year. This decrease was partially offset by interest expense on the Additional 2025 Notes which were issued in February 2018.

During the year ended December 31, 2017, we incurred a loss of approximately $115.0 million on the extinguishment of debt due to several transactions that redeemed a portion of our long-term debt. The table below denotes the notes redeemed, the reduction of the principal amount of long-term debt, the tender or make whole premium paid, the write-down of associated issuance costs and discount, and the net loss on extinguishment of debt that was recorded for each transaction:

Note Redemption	Principal Reduction	Tender / Make Whole Premium	Issuance Cost and Discount Write-down	Net Loss
		(In millions)		
2025 Notes	$ 425.0	$ 12.8	$ 16.1	$ 28.9
2022 Second Lien Notes	112.8	23.0	6.2	29.2
2020 Second Lien Notes	700.0	30.9	26.0	56.9
	$ 1,237.8	$ 66.7	$ 48.3	$ 115.0

We recorded an income tax provision of $95.8 million for the year ended December 31, 2018, resulting from the Section 382 change in ownership that took effect in December. We recorded an income tax benefit of $5.0 million for the year ended December 31, 2017, resulting from the reversal of the $5.0 million alternative minimum tax liability recorded in 2016.

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

The table included below sets forth financial information for the periods presented. The period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016 are distinct reporting periods as a result of our application of fresh-start accounting upon our emergence from chapter 11 bankruptcy on September 9, 2016 and are not comparable to prior periods. Refer to the paragraphs following the table below for a discussion around our results of operations.

	Successor		Predecessor
In thousands (except per unit and per Boe amounts)	**Year Ended December 31, 2017**	**Period from September 10, 2016 through December 31, 2016**	**Period from January 1, 2016 through September 9, 2016**
Net income (loss)	$ 535,686	$ (479,193)	$ 11,958
Operating revenues:			
Oil	340,674	139,786	248,064
Natural gas	16,194	6,756	9,511
Natural gas liquids	18,969	6,018	7,929
Other	2,128	802	1,339
Operating expenses:			
Production:			
Lease operating	61,743	22,382	50,032
Workover and other	21,739	10,510	22,507
Taxes other than income	30,757	12,364	24,453
Gathering and other	40,783	14,677	29,279
Restructuring	7,535		5,168
General and administrative:			
General and administrative	74,594	19,876	78,765
Stock-based compensation	36,757	21,519	4,876
Depletion, depreciation and accretion:			
Depletion Full cost	104,306	45,204	114,775
Depreciation Other	4,595	1,108	4,366
Accretion expense	1,306	587	1,414
Full cost ceiling impairment		420,934	754,769
(Gain) loss on sale of oil and natural gas properties	(721,573)		
Other operating property and equipment impairment			28,056
Other income (expenses):			
Net gain (loss) on derivative contracts	1,291	(27,740)	(17,998)
Interest expense and other, net	(71,097)	(28,861)	(122,249)
Reorganization items		(2,049)	913,722
Gain (loss) on extinguishment of debt	(114,931)		81,434
Income tax benefit (provision)	5,000	(4,744)	8,666
Production:			
Crude oil MBbls	7,511	3,250	7,118
Natural gas MMcf	7,439	3,011	6,560
Natural gas liquids MBbls	1,249	501	1,096
Total MBoe[(1)]	10,000	4,253	9,307
Average daily production Boe[(1)]	27,397	37,637	36,787
Average price per unit[(2)]:			
Crude oil price Bbl	$ 45.36	$ 43.01	$ 34.85
Natural gas price Mcf	2.18	2.24	1.45
Natural gas liquids price Bbl	15.19	12.01	7.23
Total per Boe[(1)]	37.58	35.87	28.53
Average cost per Boe:			
Production:			
Lease operating	$ 6.17	$ 5.26	$ 5.38
Workover and other	2.17	2.47	2.42
Taxes other than income	3.08	2.91	2.63
Gathering and other	4.08	3.45	3.15
Restructuring	0.75		0.56
General and administrative:			
General and administrative	7.46	4.67	8.46
Stock-based compensation	3.68	5.06	0.52
Depletion	10.43	10.63	12.33

(1) *Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.*

(2) *Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.*

Oil, natural gas and natural gas liquids revenues were $375.8 million, $152.6 million and $265.5 million for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. Our average daily oil and natural gas production decreased in 2017 when compared to the prior year due to our divestitures during 2017. This decrease was partially mitigated by the production associated with our assets located in the Hackberry Draw and Monument Draw areas of the Delaware Basin and our drilling activities since acquiring the assets. For the year ended December 31, 2017, production averaged 27,397 Boe/d. During the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, production averaged 37,637 Boe/d and 36,787 Boe/d, respectively. Average realized prices (excluding the effects of hedging arrangements) were $37.58 per Boe, $35.87 per Boe and $28.53 per Boe for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. Oil and natural gas prices are inherently volatile and have decreased significantly since mid-year 2014 with modest increases in 2017.

Lease operating expenses were $61.7 million, $22.4 million and $50.0 million for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. On a per unit basis, lease operating expenses were $6.17 per Boe, $5.26 per Boe and $5.38 per Boe for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. The increase in lease operating expense per Boe from 2016 levels is primarily due to reduction in our average daily production as we divested our Bakken/Three Forks assets and acquired assets in the Delaware Basin.

Workover and other expenses were $21.7 million, $10.5 million and $22.5 million for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. On a per unit basis, workover and other expenses were $2.17 per Boe, $2.47 per Boe and $2.42 per Boe for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. The decreased costs per Boe in 2017 relate to our divestiture of the Williston Basin Assets. In the past, we primarily incurred workover expenses in our Bakken/Three Forks area, specifically costs spent to restore production on wells.

Taxes other than income were $30.8 million, $12.4 million and $24.5 million for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. On a per unit basis, taxes other than income were $3.08 per Boe, $2.91 per Boe and $2.63 per Boe for year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease.

Gathering and other expenses were $40.8 million, $14.7 million and $29.3 million for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. Gathering and other expenses include gathering fees paid on our oil and natural gas production as well as rig termination or stacking charges incurred. Approximately $26.3 million, $10.7 million and $19.8 million for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively, relate to gathering and other fees paid on our oil and natural gas production. Also included are $6.8 million, $3.7 million and $8.6 million of rig stacking or termination charges for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively.

Restructuring expense was $7.5 million for the year ended December 31, 2017. During 2017, we incurred severance costs and accelerated stock-based compensation expense related to the termination of certain employees in conjunction with our divestitures. Restructuring expense for the period of January 1, 2016 through September 9, 2016 was $5.2 million, which related to severance costs and accelerated stock-based compensation expense incurred due to reductions in our workforce, as we decreased our drilling and developmental activities in response to low commodity prices.

General and administrative expense was $74.6 million, $19.9 million and $78.8 million for the year ended December 31, 2017, the period of September 10, 2016 through September 30, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. General and administrative expense in 2016 included fees associated with the effort to restructure our indebtedness, costs associated with key employee retention agreements and settlements of disputes with lease brokers and warrant holders. The decrease from 2016 is also a result of a reduction in our workforce and office lease expenses. On a per unit basis, general and administrative expenses were $7.46 per Boe, $4.67 per Boe and $8.46 per Boe for the year ended December 31, 2017, the period of September 10, 2016 through September 30, 2016 and the period of January 1, 2016 through September 9, 2016, respectively.

Stock-based compensation expense was $36.8 million, $21.5 million and $4.9 million, for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. Stock-based compensation expense increased from the Predecessor period due to equity awards made since our emergence from reorganization under chapter 11.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. On a per unit basis, depletion expense was $10.43 per Boe, $10.63 per Boe and $12.33 per Boe, for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. The decrease in depletion expense and the depletion rate per Boe from 2016 levels is attributable to decreases in the amortizable base due to our full cost ceiling test impairments recorded in 2016.

We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling", based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our estimated proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. During 2016, the net book value of our oil and gas properties at March 31, June 30, and September 30, 2016 exceeded the respective ceiling amounts for each period. We recorded a full cost ceiling test impairment before income taxes of $420.9 million for the period of September 10, 2016 through September 30, 2016. The impairment at September 30, 2016 primarily reflects the pricing differences between the first-day-of-the-month average price for the preceding twelve months required by Regulation S-X, Rule 4-10 and ASC 932 used in calculating the ceiling test and the forward-looking prices required by ASC 852 to estimate the fair value of our oil and natural gas properties on the fresh-start reporting date, September 9, 2016. We recorded full cost ceiling test impairments before income taxes totaling $754.8 million for the period January 1, 2016 through September 9, 2016. The ceiling test impairments were driven by decreases in the first-day-of-the-month average prices for crude oil used in the ceiling test calculations since December 31, 2015. Changes in commodity prices, production rates, levels of reserves, future development costs, transfers of unevaluated properties to our full cost pool, capital spending and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

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Under the full cost method of accounting, sales of oil and gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless the adjustment significantly alters the relationship between capitalized costs and estimated proved reserves. If the Williston and El Halcón Divestitures were accounted for as adjustments of capitalized costs with no gain or loss recognized, the adjustments would have significantly altered the relationship between capitalized costs and estimated proved reserves at the time of each of the transactions. Accordingly, we recognized a gain on the sale of the Williston Assets of $485.9 million and a gain on the sale of the El Halcón Assets of $235.7 million for the year ended December 31, 2017. The carrying value of the properties sold was determined by allocating total capitalized costs within the full cost pool between properties sold and properties retained based on their relative fair values.

We review our gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360. For the period of January 1, 2016 through September 9, 2016, we recorded a non-cash impairment charge of $28.1 million. The impairment relates to our gross investments of $32.8 million in gas gathering infrastructure that were not likely to be economically recoverable due to our shift in exploration, drilling and developmental plans to our most economic areas as a result of the low commodity price environment.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. At December 31, 2017, we had a $0.7 million derivative asset, all of which was classified as current, and we had a $27.0 million derivative liability, $19.2 million of which was classified as current. We recorded a net derivative gain of $1.3 million ($16.5 million net unrealized loss and $17.8 million net realized gain on settled contracts) for the year ended December 31, 2017, compared to a net derivative loss of $27.7 million ($112.4 million net unrealized loss and $84.7 million net realized gain on settled contracts) and $18.0 million ($263.7 million net unrealized loss and $245.7 million net realized gain on settled contracts) for the period of September 10, 2016 through December 31, 2016 and for the period of January 1, 2016 through September 9, 2016, respectively.

Interest expense and other was $71.1 million, $28.9 million and $122.2 million for the year ended December 31, 2017, the period of September 10, 2016 through December 31, 2016 and the period of January 1, 2016 through September 9, 2016, respectively. Capitalized interest for the period of January 1, 2016 through September 9, 2016 was $68.2 million. The Successor Company's accounting policy on the capitalization of interest establishes thresholds for the determination of a development project for the purpose of interest capitalization. The decrease in interest expense from our Predecessor period was primarily due to the discontinuance of interest expense on our senior notes that were cancelled as part of our chapter 11 bankruptcy proceedings.

Reorganization items represent (i) expenses or income incurred subsequent to July 27, 2016 (when we filed voluntary petitions for relief under chapter 11) as a direct result of the reorganization Plan,

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(ii) gains or losses from liabilities settled, and (iii) fresh-start accounting adjustments. The following table summarizes the net reorganization items (in thousands):

Successor	Predecessor