MONTAGE
RESOURCES


# MONTAGE RESOURCES 2018 ANNUAL REPORT

## Dear Fellow Shareholders:

2018 was a transformative year that repositioned Montage Resources for financial success in 2019 and beyond. Early in 2018, the company initiated a process to evaluate opportunities to maximize shareholder value with the outcome resulting in a strategic business combination of Eclipse Resources and its offsetting pure-play Marcellus-Utica peer, Blue Ridge Mountain Resources. The strategic combination meaningfully improved the corporate scale of the company from both a production and cash flow perspective, increased the Company's attractive drilling inventory, upgraded the balance sheet, enhanced corporate liquidity, and balanced corporate midstream and downstream commitments to allow development flexibility and improved commodity pricing netbacks. I would like to thank the teams from both Eclipse Resources and Blue Ridge Mountain Resources for their professional and diligent efforts in consummating this transformational merger transaction while remaining highly focused on delivering operational excellence in 2018. Through outstanding cooperation during the transition period and closing process, Montage Resources was able to align corporate and development goals to realize accelerated merger integration benefits that allowed the Company to formulate an optimized 2019 capital plan.

As we set the course for 2019 with the new management team assuming control of the pro forma Company, a strategy shift has been initiated that is aimed at enhancing the focus on corporate, operational, and financial efficiencies in order to demonstrate meaningful progress toward free cash flow generation while growing the company in a disciplined manner. Montage Resources has set in motion its "Focus Five" plan that consists of the following core principles: cash flow and returns, cost structure improvement and integration, financial and operational flexibility, portfolio optimization, and enhancing scale with disciplined growth. I believe these principles will help differentiate the Company among its peers in unlocking corporate value throughout 2019 and into the future.

Underpinning these key objectives is a deliberate shift in our development approach that is enabled by our deep, high-quality inventory that provides attractive rates of return. The development plan being executed in 2019 is aimed towards maximizing cash flow and arresting outspend, creating and maintaining an attractive balance sheet, optimizing operational and strategic flexibility, and focuses on a de-risked operational plan in highly delineated condensate and dry gas areas. In conjunction with the closing, the Company finalized its new credit facility that resulted in a borrowing base of $375 million, which is an increase of $150 million and, when coupled with the cash flow from operations, will provide ample liquidity to internally fund our planned operations for the foreseeable future.

For the full year 2018, our average daily production was approximately 343 million cubic feet equivalent per day while our total pre-hedge revenues grew to approximately $515 million, a 34% increase over the previous year and a Company record. On the expense side, our per unit cash production costs, including firm transportation costs were $1.41 per million cubic feet equivalent while our cash general and administrative costs dropped to $0.29 per million cubic feet equivalent, a 6% reduction from the previous year. As the Company continues its integration throughout 2019, we anticipate a further 35% drop in cash general and administrative costs, on a per unit basis, as these corporate synergies are applied.

In our Flat Castle project in Pennsylvania, the Company continues to monitor the Painter 2H well and I am pleased with the strong production results that have been achieved to-date which truly highlight the potential for this area. The well's production has continued at target rate that is aligning with the high end of our publicly stated EUR range of 2.2 Bcf per 1,000 feet of lateral. We continue to monitor this well's performance closely in order to refine the long-term potential for this area while also assessing strategic options for the Flat Castle prospect in order to accelerate value for this high quality acreage.

The Marcellus area in Southeast Ohio is complemented through the additional acreage provided by the merger and expands into West Virginia. The Marcellus development area is condensate rich and we remain excited as it becomes a more prevalent part of our drilling program in 2019. We can now co-develop both the Utica and Marcellus on the same pad, further lowering our cost structure and improving operational efficiencies. In addition, with approximately 150 Marcellus locations, based upon our current type curve assumptions, we continue to see this as an area that warrants substantial capital allocation and will enhance the value of the company by delivering highly economic, liquids rich production.

The Company also made the strategic decision during 2018 to re-order the drill schedule and continue to focus on the liquids portion of our acreage. This decision has allowed us to take advantage of the improvement in the oil macro price environment, while additionally allowing us to achieve more commodity product diversification. For the full year 2019 we plan to turn approximately, 11-13 gross (10.5-12.4 net) Utica condensate wells to sales and approximately 10-12 gross (9.6-11.6 net) Marcellus wells to sales. Optionality to liquids exposure is something we want to continue to focus on and is one of the key aspects of our Company. Given that approximately 50% of our acreage is in the liquids-rich areas of the Utica and Marcellus and produces a significant amount of condensate, we remain highly advantaged vs our Appalachian peers, with current single well rates of return that are competitive with some of the best plays in the country.

The industry is clearly faced with a new set of financial expectations and as we move through 2019 we will execute on the plan we have created that mirrors our "Focus Five" strategic priorities and reinforces our commitment towards disciplined growth and progressing organic free cash flow generation. Decreasing our cycle times while continuing to build scale will allow the Company to enhance its operating margins, lower its cost of capital, be well positioned in terms of base production and significantly improve its cost structure. We are looking forward to the continued integration of the teams and the potential opportunities this business model can provide.

I am pleased with the many successes we have had in 2018 and proud of the team we have assembled here at Montage Resources. I appreciate the vision, dedication and operational execution experience that they provide as we focus on maximizing shareholder value via the exceptional assets and strong financial positioning of the Company. I would also like to thank the Board of Directors for the guidance they have provided with the execution of the strategic transaction over the past year. They bring a wealth of expertise that is unrivaled and continue to show their constant encouragement for what we are building here at Montage Resources.

Thank you again for investing in Montage Resources and for your ongoing support.

Respectfully,

**John K. Reinhart**
President and Chief Executive Officer

# 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**

**or**

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

**For the transition period from to**

**Commission File Number: 001-36511**

# Montage Resources Corporation
**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware** | **46-4812998** |
| **(State or other jurisdiction of incorporation or organization)** | **(I.R.S. Employer Identification No.)** |
| **122 West John Carpenter Freeway, Suite 300 Irving, TX** | **75039** |
| **(Address of principal executive offices)** | **(Zip code)** |

**(469) 444-1647**
**(Registrant's telephone number, including area code)**

**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 $0.01 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 ☐ No ☒

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

Indicate by check mark whether the registrant (1) 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 ☒ No ☐

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

| | | | |
|---|---|---|---|
| Large accelerated filer | ☐ | Accelerated filer | ☒ |
| Non-accelerated filer | ☐ | Smaller reporting company | ☐ |
| | | Emerging growth company | ☒ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☒

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2018, the last business day of the most recently completed second fiscal quarter, was approximately $140 million.

Number of shares of the registrant's common stock outstanding at March 13, 2019: 35,193,719 shares.

Documents incorporated by reference: Portions of the registrant's proxy statement for its 2019 annual meeting of stockholders to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end are incorporated by reference into Part III of this Annual Report on Form 10-K.

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## Cautionary Statement Regarding Forward-Looking Statements

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

Forward-looking statements may include statements about, among other things:

- realized prices for natural gas, natural gas liquids ("NGLs") and oil and the volatility of those prices;
- write-downs of our natural gas and oil asset values due to declines in commodity prices;
- our business strategy;
- our reserves;
- general economic conditions;
- our financial strategy, liquidity and capital required for developing our properties and the timing related thereto;
- the timing and amount of our future production of natural gas, NGLs and oil;
- our hedging strategy and results;
- future drilling plans;
- competition and government regulations, including those related to hydraulic fracturing;
- the anticipated benefits under our commercial agreements;
- marketing of natural gas, NGLs and oil;
- leasehold and business acquisitions and joint ventures;
- leasehold terms expiring before production can be established and our costs to extend such terms;
- the costs, terms and availability of gathering, processing, fractionation and other midstream services;
- credit markets;
- uncertainty regarding our future operating results, including initial production rates and liquids yields in our type curve areas; and
- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil. These risks include, but are not limited to, legal and environmental risks, drilling and other operating risks, regulatory changes, commodity price volatility and the significant decline of the price of natural gas, NGLs and oil from historical highs, inflation, lack of availability of drilling, production and processing equipment and services, counterparty credit risk, the uncertainty inherent in estimating natural gas, NGLs and oil reserves and in projecting future rates of production, cash flows and access to capital, risks associated with our level of indebtedness, the timing of development expenditures, and the other risks described in "Item 1A. Risk Factors" of this Annual Report.

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

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

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

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

## Glossary of Oil and Natural Gas Terms

As used in this Annual Report, unless the context indicates or otherwise requires, the following terms have the following meanings:

- "Bbl" refers to a standard barrel containing 42 U.S. gallons;
- "Bbls/d" refers to Bbls per day;
- "Bcfe" refers to one billion cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs;
- "Boe" refers to one barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil;
- "Btu" refers to one British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit;
- "Completion" refers to the process of treating a drilled well followed by 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;
- "Condensate" or "Condensate Window" refers to the area in which we generally expect Utica Shale wells to produce natural gas having a heat content greater than 1,210 Btu, with an initial condensate yield of approximately 60 to 300 barrels per MMcf of natural gas produced;
- "Developed acreage" refers to the number of acres that are allocated or assignable to productive wells or wells capable of production;
- "Differential" refers to an adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas;
- "Dry Gas" refers to the area in which we generally expect Utica Shale wells to produce natural gas having a heat content between 1,010 Btu and 1,150 Btu with no initial condensate yield;
- "Dth" refers to a thermal unit, and is equal to one million Btus;
- "Dth/d" refers to Dths per day;
- "Dry hole" or "dry well" refers to 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;

- “Exploration” refers to a development or other project that may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects;
- “Field” refers to an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations;
- “Formation” refers to a layer of rock that has distinct characteristics that differs from nearby rock;
- “Gal” refers to gallons;
- “Gal/d” refers to gallons per day;
- “Gross acres” or “gross wells” refers to the total acres or wells, as the case may be, in which a working interest is owned;
- “Horizontal drilling” refers to a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval;
- “Identified drilling locations” refers to total gross (net) resource play locations that we may be able to drill on our existing acreage. Actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors;
- “Marcellus Condensate” or “Marcellus Area” refers to the area in which we generally expect Marcellus Shale wells to produce a natural gas having a heat content of approximately 1,300 Btu, with an initial condensate yield of approximately 60-140 barrels per MMcf of natural gas produced;
- “MBbl” refers to one thousand barrels;
- “Mcf” refers to one thousand cubic feet;
- “Mcfe” refers to one thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs;
- “Mcf/d” refers to Mcfs per day;
- “MMBbls” refers to one million barrels;
- “MMBoe” refers to one million Boe;
- “MMBtu” refers to one million British thermal units;
- “MMcf” refers to one million cubic feet;
- “MMcfe” refers to one million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs;
- “Net acres” refers to the amount of leased real estate that a petroleum and/or natural gas company has a true working interest in. Net acres express actual percentage interest when a company shares its working interest with another company; the total acreage under lease by a company is referred to as gross acres. Net acres account for the Company’s percentage interest, multiplied by the gross acreage. If a company holds the entire working interest, its net acreage and gross acreage will be the same;
- “Net production” refers to production that is owned by us less royalties and production due others;
- “NGLs” refers to natural gas liquids, which are hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline;
- “NYMEX” refers to the New York Mercantile Exchange;
- “Operator” refers to the individual or company responsible for the exploration and/or production of an oil or natural gas well or lease;

- “Plugging” refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface;
- “Productive well” refers to a well that is expected to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceeds production expenses and taxes;
- “Prospect” refers to a geological feature mapped as a location or probable location of a commercial oil and/ or gas accumulation. A prospect is defined as a result of geophysical and geological studies allowing the identification and quantification of uncertainties, probabilities of success, estimates of potential resources and economic viability;
- “Proved undeveloped reserves” refers to 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;

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

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

  (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir (as defined in Rule 4-10(a) (2) of Regulation S-X), or by other evidence using reliable technology establishing reasonable certainty;
- “PV-10” refers to, when used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using sales prices used in estimating proved oil and gas reserves and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC;
- “Realized price” refers to the cash market price less all expected quality, transportation and demand adjustments;
- “Reservoir” refers to 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 separate from other reservoirs;
- “Rich Condensate” or “Rich Condensate Window” refers to the area in which we generally expect Utica Shale wells to produce natural gas having a heat content greater than 1,300 Btu, with an initial condensate yield of approximately 80 to 200 barrels per MMcf of natural gas produced;
- “Rich Gas” or “Rich Gas Window” refers to the area in which we generally expect Utica Shale wells to produce natural gas having a heat content between 1,150 Btu and 1,210 Btu, with an initial condensate yield of approximately 0 to 60 barrels per MMcf of natural gas produced;
- “SEC” refers to the United States Securities and Exchange Commission;
- “Spacing” refers to the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies;
- “Spot market price” refers to the cash market price without reduction for expected quality, transportation and demand adjustments;

- “Standardized measure” refers to discounted future net cash flows estimated by applying sales prices used in estimating proved oil and gas reserves to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate;
- “Undeveloped acreage” refers to 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;
- “Unit” refers to the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement;
- “Working interest” refers to the right granted to the lessee of a property to explore for and to produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis;
- “WTI” refers to West Texas Intermediate; and
- The terms “development project,” “development well,” “exploratory well,” “proved developed reserves,” “proved reserves” and “reserves” are defined by the SEC.

## PART I

### Items 1 and 2. Business and Properties

### Our Company

Montage Resources Corporation, a Delaware corporation formed in 2014, is an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin. As of December 31, 2018, we had assembled an acreage position approximating 241,000 net acres in Ohio and Pennsylvania. We intend to focus on developing our substantial inventory of horizontal drilling locations during commodity price environments that will allow us to generate attractive returns and will continue to opportunistically add to this acreage position where we can acquire acreage at attractive prices. As used in this Annual Report, unless the context indicates or otherwise requires, "Montage" "Montage Resources," the "Company," "we," "our," "us" and like terms refer collectively to Montage Resources Corporation and its consolidated subsidiaries.

### Our Properties

As of December 31, 2018, we had approximately 134,000 net acres in the Utica Shale fairway, which we refer to as the Utica Core Area and approximately 14,500 net acres of stacked pay opportunity in our Marcellus Area. We are the operator of approximately 94% of our proved reserves within the Utica Core Area and our Marcellus Area. Additionally, we own approximately 107,000 net acres (which are approximately 94% held by production) outside of the Utica Core Area that may be prospective for the oil window of the Utica Shale.

#### *Utica Shale*

The Ordovician-aged Utica Shale is an unconventional reservoir comprised of organic-rich black shale, with most production occurring at vertical depths between 6,000 and 10,000 feet. The richest and thickest concentration of organic-carbon content is present within the Point Pleasant layer of the Lower Utica formation. Across the Utica Core Area, the eastern boundary is more thermally mature and expected to produce dry gas, while the western boundary is less thermally mature and expected to produce a greater proportion of condensate and NGLs in addition to natural gas. We classify our acreage between these boundaries as being prospective for Dry Gas, Rich Gas, or Condensate.

#### *Indian Castle/Flat Creek Shales*

The Indian Castle and Flat Creek Shales consist of organic-rich black shale, and we refer to them collectively as the "Flat Castle" area. They are Ordovician in age and are correlative to the Utica, Point Pleasant and Logana Shales of Ohio. The core of the area is located in Tioga County, Pennsylvania. The top of the Flat Castle area is between 9,500 and 10,500 feet deep. As of December 31, 2018, we had approximate 45,000 net acres in the core of the area. The shales in the Flat Castle area are very mature and produce Dry Gas in the area.

#### *Marcellus Shale*

The Marcellus Shale consists of organic-rich black shale, with most production occurring at vertical depths between 5,000 and 8,000 feet. As of December 31, 2018, we had approximately 14,500 net acres of stacked pay opportunity in the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as our Marcellus Area. The reservoir underlying this acreage is less thermally mature than the Marcellus Shale in Southwestern Pennsylvania, and consequently, we believe natural gas production from this area will yield significant NGLs and condensate.

## Activity

Through December 31, 2018, we, or our operating partners, had commenced drilling 256 gross (136.1 net) wells within the Utica Core Area and our Marcellus Area, which are summarized below:

| | Operated Gross Wells | | | | Non-Operated Gross Wells | | | |
|---|---|---|---|---|---|---|---|---|
| Type Curve Area[1] | Producing to Sales[2] | Awaiting Turn to Sales | Awaiting Completion/ Completing | Drilling | Producing to Sales | Awaiting Turn to Sales | Awaiting Completion/ Completing | Drilling |
| Dry Gas | 50 | — | 10 | 2 | 29 | — | — | — |
| Rich Gas | — | — | — | — | 22 | — | — | — |
| Condensate | 78 | — | 2 | 2 | 55 | — | — | — |
| Flat Castle | 2 | — | — | — | — | — | — | — |
| Total Utica Core Area | 130 | — | 12 | 4 | 106 | — | — | — |
| Marcellus Condensate[2] | 3 | — | — | — | 1 | — | — | — |
| Marcellus Area | 3 | — | — | — | 1 | — | — | — |
| **Total** | **133** | **—** | **12** | **4** | **107** | **—** | **—** | **—** |

| | Operated Net Wells | | | | Non-Operated Net Wells | | | |
|---|---|---|---|---|---|---|---|---|
| Type Curve Area[1] | Producing to Sales[2] | Awaiting Turn to Sales | Awaiting Completion/ Completing | Drilling | Producing to Sales | Awaiting Turn to Sales | Awaiting Completion/ Completing | Drilling |
| Dry Gas | 39.4 | — | 4.9 | 1.7 | 2.7 | — | — | — |
| Rich Gas | — | — | — | — | 2.8 | — | — | — |
| Condensate | 65.0 | — | 1.6 | 1.7 | 11.6 | — | — | — |
| Flat Castle | 2.0 | — | — | — | — | — | — | — |
| Total Utica Core Area | 106.4 | — | 6.5 | 3.4 | 17.1 | — | — | — |
| Marcellus Condensate[2] | 2.5 | — | — | — | 0.2 | — | — | — |
| Marcellus Area | 2.5 | — | — | — | 0.2 | — | — | — |
| **Total** | **108.9** | **—** | **6.5** | **3.4** | **17.3** | **—** | **—** | **—** |

(1) All producing wells are classified as gas wells, except 1 gross (0.1 net) Non-Operated producing oil well.
(2) Excludes 1 gross (1 net) Marcellus producing well outside our defined type curve area.

As of December 31, 2018, our estimated proved reserves were 1,864.7 Bcfe, or 310.8 MMBoe, an increase of 28% from December 31, 2017 estimated proved reserves of 1,458.6 Bcfe, or 243.1 MMBoe, based on reserve reports prepared by Software Integrated Solutions Division of Schlumberger Technology Corporation ("SIS"), our independent petroleum engineers for the year ended December 31, 2018, and Netherland, Sewell & Associates, Inc. ("NSAI"), our independent petroleum engineers for the year ended December 31, 2017. As of December 31, 2018, our estimated proved reserves were approximately 82% natural gas, 11% NGLs and 7% oil, and approximately 36% were proved developed reserves. The following table provides information regarding our proved reserves as of December 31, 2018, 2017, and 2016:

| | Estimated Total Proved Reserves | | | | | | |
|---|---|---|---|---|---|---|---|
| | Natural Gas (Bcf) | Oil (MMBbls) | NGLs (MMBbls) | Total (Bcfe) | Total (MMBoe) | % Liquids | % Developed |
| December 31, 2016 | 386.4 | 5.2 | 8.7 | 469.4 | 78.2 | 17.7% | 63.4% |
| December 31, 2017 | 1,090.1 | 19.5 | 41.9 | 1,458.6 | 243.1 | 25.3% | 31.3% |
| December 31, 2018 | 1,531.2 | 20.9 | 34.7 | 1,864.7 | 310.8 | 17.9% | 36.0% |

## Net Undeveloped Locations

The following table provides a summary of our approximate net acreage, net producing locations and net undeveloped locations as of December 31, 2018:

| | As of December 31, 2018 | | |
|---|---|---|---|
| | Approximate Net Acreage | Net Producing Locations | Net Undeveloped Locations(1) |
| Dry Gas | 46,039 | 42.1 | 90.2 |
| Rich Gas | 6,668 | 2.8 | 15.0 |
| Condensate | 36,071 | 76.6 | 77.6 |
| Flat Castle | 45,141 | 2.0 | 87.3 |
| Marcellus Condensate(2) | 14,580 | 2.6 | 72.0 |
| **Total** | 148,499 | 126.1 | 342.1 |

(1) Based on our reserve report as of December 31, 2018, we had 94 net drilling locations associated with proved undeveloped reserves and 2 net locations associated with proved developed non-producing reserves. Please see "—Determination of Drilling Locations" for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Our drilling locations are also scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill our drilling locations. Please see "Item 1A. Risk Factors" for more information.

(2) Excludes 1 gross (1 net) Marcellus producing well outside our defined type curve area.

### *Determination of Drilling Locations*

Net undeveloped locations are calculated by taking our total net acreage and multiplying such amount by a risk factor, which is then divided by our expected well spacing. In each type curve area, we apply a 10% risk factor to our net acreage to account for inefficient unitization, acreage expirations and the risk associated with our inability to force pool under state law. We then subtract net producing wells to arrive at net undeveloped locations.

- Undeveloped Net Dry Gas Locations – We assume these locations have 16,000 foot laterals and 1,000 foot spacing between wells which yields approximately 374 acre spacing. As of December 31, 2018, we had approximately 46,039 net acres in the Dry Gas area, which, after removing net producing locations, results in 90.2 net undeveloped locations.

- Undeveloped Net Rich Gas Locations – We assume these locations have 16,000 foot laterals and 1,000 foot spacing between wells which yields approximately 374 acre spacing. As of December 31, 2018, we had approximately 6,668 net acres in the Rich Gas area, which, after removing net producing locations, results in 15.0 net undeveloped locations.

- Undeveloped Net Condensate Locations – We assume these locations have 16,000 foot laterals and 750 foot spacing between wells which yields approximately 281 acre spacing. As of December 31, 2018, we had approximately 36,071 net acres in the Condensate area, which, after removing net producing locations, results in 77.6 net undeveloped locations.

- Undeveloped Net Flat Castle Locations – We assume these locations have 16,000 foot laterals and 1,200 foot spacing between wells which yields approximately 459 acre spacing. As of December 31, 2018, we had approximately 45,141 net acres in the Flat Castle area, which, after removing net producing locations, results in 87.3 net undeveloped locations.

- Undeveloped Net Marcellus Condensate Locations – We assume these locations have 10,000 foot laterals and 750 foot spacing between wells which yields approximately 177 acre spacing. As of December 31, 2018, we had approximately 14,580 net acres in the Marcellus Condensate area, which, after removing net producing locations, results in 72.0 net undeveloped locations.

**Midstream Agreements**

We work closely with our midstream partners to coordinate our drilling and completion schedule with their well hook up and facility construction schedule to ensure sufficient capacity is available to minimize any delays in turning production into sales.

We have contracted for firm gathering, processing and fractionation capacity for a significant portion of our operated acreage in the Condensate and Rich Gas Windows of the Utica Core Area with Blue Racer Midstream, LLC ("Blue Racer"), a joint venture between First Reserve and Caiman Energy II, LLC. This gas-processing agreement does not require us to make minimum volume deliveries or shortfall payments.

In 2018, we amended our firm gas gathering services agreement with Eureka Midstream LLC ("Eureka Midstream") to gather and compress a substantial portion of our operated production of Dry Gas through Eureka Midstream's system. This new agreement replaced an existing agreement with Eureka Midstream that we had entered into in 2013. Under the new 20-year agreement, we have firm gathering capacity, which increases during the term of the agreement, from between approximately 275 MMcf to 900 MMcf per day. This agreement provides for reduced gathering and compression charges. Through this agreement, we obtained access to additional downstream pipelines and markets connected to Eureka Midstream including the Rover Pipeline System, accessing our firm transportation capacity. This midstream agreement requires us to make minimum volume deliveries to the Eureka Midstream gathering system or shortfall payments. The following table illustrates the minimum volume commitments under our agreement with Eureka Midstream:

| Term | Natural Gas (Mcf/d) |
|---|---|
| January 2019 – December 2019 | 212,500 |
| January 2020 – December 2020 | 310,000 |
| January 2021 – December 2021 | 355,000 |
| January 2022 – December 2022 | 400,000 |
| January 2023 – December 2023 | 362,500 |
| January 2024 – December 2024 | 331,250 |
| January 2025 – December 2025 | 250,000 |
| January 2026 – December 2026 | 202,500 |
| January 2027 – December 2027 | 165,000 |
| January 2028 – December 2028 | 140,000 |
| January 2029 – December 2029 | 122,500 |

During 2018, we assigned our option to purchase all of the outstanding equity interests of Cardinal NE Holdings, LLC ("Cardinal"), a wholly owned subsidiary of Cardinal Midstream II, LLC, which owns midstream infrastructure with associated gathering rights on acreage in the Flat Castle area, to DTE Pipeline Company ("DTE"). The option was exercised and DTE completed its acquisition of Cardinal in July 2018. The legacy gathering agreement was assigned to DTE and does not require us to make minimum volume deliveries or shortfall payments.

The following table illustrates the natural gas firm transportation and sales volumes associated with our operated assets:

| Firm Sales & Transportation | Start Date | Term | Volume (Dth/d) | Market |
|---|---|---|---|---|
| Columbia Gas Transmission ("TCO")............................ | October 2016 | 15 years | 205,000 | TCO Pool |
| Rover Pipeline System ......... | June 2018 | 15 years | 100,000 | Gulf Coast |
| Rover Pipeline System ......... | June 2018 | 15 years | 50,000 | Canada |

As of December 31, 2018, our natural gas firm transportation commitments through 2023 include:

| Year Ended December 31, | Volume of Natural Gas (MMBtu/d) |
|---|---|
| 2019 | 355,000 |
| 2020 | 355,000 |
| 2021 | 355,000 |
| 2022 | 355,000 |
| 2023 | 355,000 |

The minimum demand fees related to these volume and firm transportation agreements that were in place as of December 31, 2018 are reflected in our table of contractual obligations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Cash Contractual Obligations." See "Item 1A. Risk Factors" for a discussion of risks and uncertainties relating to our gathering, processing and fractionation arrangements.

In March 2014, we entered into a 20-year contract with Shell Chemical, LP ("Shell Chemical") for the sale of ethane to Shell Chemical's proposed Appalachian cracker project in Monaca, Pennsylvania. Under the terms of the contract, we agreed to sell to Shell Chemical, at a minimum, all of our "Must Recover Ethane" (i.e., 30% of total recoverable ethane) at Blue Racer's fractionation facility near Natrium, West Virginia. In June 2016, Shell Chemical provided notice of a positive final investment decision and election to purchase our ethane.

In August 2014, we entered into an agreement with EnLink Midstream Operating, LP ("EnLink Midstream") for the marketing of our condensate and operation of our condensate stabilization facilities. Under the terms of the agreement, among other things, EnLink Midstream purchased two of our existing condensate stabilization facilities, and plans to construct and operate additional facilities to support our drilling program in the Utica Shale. This midstream agreement requires us to make minimum volume deliveries to the condensate stabilization facilities or shortfall payments. The following table illustrates the minimum volume commitments under our agreement with EnLink Midstream:

| Term | Natural Gas (Mcf/d) | Term | Oil (Bbl/d) | Term | Water (Bbl/d) |
|---|---|---|---|---|---|
| January 2019 – December 2019 | 92,400 | January 2019 – June 2020 | 10,052 | January 2019 – May 2019 | 5,000 |
| January 2020 – June 2020 | 82,300 | | | | |

In December 2014, we entered into a 10-year firm transportation and marketing agreement with Blue Racer to market a substantial portion of our operated production of propane and butane through Blue Racer's firm capacity on Sunoco's Mariner East II Project. Commencing operations in late 2018, the Mariner East II Project connects the NGL resources in the Marcellus and Utica Shale to Sunoco's existing infrastructure and international port at its Marcus Hook facility near Philadelphia. During 2018, we modified the agreement to eliminate minimum volume commitments or shortfall payments, while maintaining our ability to market a portion of our operated production of propane and butane through the Mariner East II project. Through this agreement, we will export propane and butane in order to potentially capture the premium pricing offered by international markets, but also retain the ability to sell domestically.

In April 2017, we entered into a 2-year hauling and marketing agreement with Marathon Petroleum Company LP ("Marathon" or "Marathon Petroleum") to sell condensate volumes. As a part of this contract, Marathon will pick up the produced condensate at our stabilization facilities and well pads and haul it away utilizing their own fleet of vehicles or third-party services. The title and risk of loss will pass to Marathon at the intake flange of our stabilization facilities under the terms of this contract.

## Recent Developments

### *BRMR Merger*

On February 28, 2019, the Company completed its previously announced business combination transaction with Blue Ridge Mountain Resources, Inc. ("BRMR") pursuant to that certain Agreement and Plan of Merger, dated as of August 25, 2018 and amended as of January 7, 2019 (the "Merger Agreement"), by and among the Company, Everest Merger Sub Inc., a Delaware corporation and a wholly owned subsidiary of the Company ("Merger Sub"), and BRMR. Pursuant to the Merger Agreement, Merger Sub merged with and into BRMR with BRMR continuing as the surviving corporation and a wholly owned subsidiary of the Company (the "BRMR Merger").

As a result of the BRMR Merger, each share of common stock, par value $0.01 per share, of BRMR issued and outstanding immediately prior to the effective time of the BRMR Merger (the "Effective Time"), excluding certain Excluded Shares (as such term is defined in the Merger Agreement), was converted into the right to receive from the Company 0.29506 of a validly issued, fully-paid, and nonassessable share of common stock, par value $0.01 per share, of the Company. The exchange ratio reflects an adjustment to account for the 15-to-1 reverse stock split described below. Former stockholders of BRMR will receive cash for any fractional shares of the Company's common stock to which they might otherwise be entitled as a result of the BRMR Merger. In addition, upon completion of the BRMR Merger, all shares of BRMR restricted stock and all BRMR restricted stock units and performance interest awards were converted into the right to receive shares of common stock of the Company or cash, in each case as specified in the Merger Agreement.

BRMR, a Delaware corporation formed in 1997, is an independent exploration and production company engaged in the acquisition, development and production of natural gas, NGLs and oil. BRMR is active in two of the most prolific unconventional shale resource plays in North America, the Marcellus and Utica Shales. As of December 31, 2018, BRMR held approximately 95,300 net surface leasehold acres in the Marcellus and Utica Shales in Ohio and West Virginia, approximately 85,100, or 89%, of which are undeveloped. Approximately 81% of BRMR's total net surface acres in these areas are held by production. BRMR is the operator on approximately 98% of this net acreage and holds an average 78% working interest across the position within developed units.

### *Reverse Stock Split*

Effective immediately prior to the Effective Time on February 28, 2019, the Company effected a 15-to-1 reverse stock split with respect to the issued and outstanding shares of its common stock. Holders of shares of the Company's common stock immediately prior to the Effective Time will receive cash for any fractional shares of the Company's common stock to which they might otherwise be entitled as a result of the reverse stock split. The reverse stock split lowered the par value to reflect the reduced shares with the offset to additional paid-in-capital. All issued and outstanding share and per share amounts presented in this Annual Report have been adjusted retroactively to reflect the reverse stock split in accordance with ASC 505 "Equity".

### *Name Change*

Following the Effective Time on February 28, 2019, the Company effected a change in its legal name to "Montage Resources Corporation" through a Certificate of Ownership and Merger providing for a short-form merger pursuant to Section 253 of the General Corporation Law of the State of Delaware pursuant to which a subsidiary formed solely for the purpose of the name change was merged with and into the Company with the Company remaining as the surviving corporation in the merger. The short-form merger had the effect of amending the Company's certificate of incorporation to reflect the Company's new legal name.

### *Amendment to the Revolving Credit Facility*

On February 28, 2019, the Company amended and restated the credit agreement governing its revolving credit facility to, among other things, increase the borrowing base from $225 million to $375 million and extend the maturity date thereof to approximately five years after the closing of the BRMR Merger. The amended and restated credit agreement also adjusted the ratio of Consolidated Total Funded Net Debt to EBITDAX (as such terms are defined in the amended and restated credit agreement) to provide that the Company will not, as of the last day of any fiscal quarter (commencing with the fiscal quarter ending March 31, 2019), permit its ratio of Consolidated Total Funded Net Debt to EBITDAX for the four previous fiscal quarters to be greater than 4.00 to 1.00.

### *2019 Capital Budget*

Our Board of Directors recently approved an initial capital budget for 2019 of between approximately $375 - $400 million, allocated approximately 90% for drilling and completions activities and approximately 10% for land activities and other capital requirements. The 2019 capital budget is expected to be substantially funded through internally generated cash flows, the Company's current cash balance and borrowings under our revolving credit facility.

## Oil and Natural Gas Data

### *Proved Reserves*

*Evaluation and Review of Proved Reserves.* Our historical proved reserve estimates were prepared by SIS for the year ended December 31, 2018 and NSAI for all prior years. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Neither SIS and nor NSAI own an interest in any of our properties, nor are they employed by us on a contingent basis. A copy of SIS proved reserve report as of December 31, 2018 and NSAI's proved reserve reports as of December 31, 2017 and 2016 are attached hereto as exhibits.

We maintain an internal staff of engineers and geoscience professionals who work closely with SIS to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets. Our internal technical team members meet with SIS periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information for our properties to SIS, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Adam Caputo, our Manager, Reserves Reporting, is primarily responsible for overseeing the preparation of all of our reserve estimates. Mr. Caputo is an engineer with approximately eight years of reservoir and operations experience and our geoscience staff has an average of approximately 10 years of industry experience.

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

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by Mr. Caputo or under his direct supervision;
- review by Mr. Caputo of all of our reported proved reserves at the close of each quarter, prior to the closing of the BRMR merger, including the review of all significant reserve changes and all new proved undeveloped reserves additions by our Chief Executive Officer, Chief Operating Officer, Chief Financial Officer and Executive Vice President, Corporate Development and Geosciences. Following the close of the BRMR Merger the review of all significant reserve changes and all new proved undeveloped reserve additions will be done by the Executive Vice President, Resources Planning and Development;
- direct reporting responsibilities by Mr. Caputo to our Chief Operating Officer; and
- verification of property ownership by our land department.

SIS evaluated the proved reserves of 1,864.7 Bcfe as of December 31, 2018. Schlumberger Technology Corporation was founded in 1926 and is the world's leading provider of technology for reservoir characterization, drilling, production and process to the oil and natural gas industry. SIS provides consulting, information management, and IT infrastructure services and sells proprietary software to customers in the oil and natural gas industry. SIS also offers expert consulting services for reservoir characterization, field development planning and production enhancement. The Lead Evaluator for the evaluation was Charles M. Boyer II, and his qualifications, independence, objectivity, and confidentiality meet the 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. He has over 27 years of practical experience in the estimation and evaluation of reserves. Mr. Boyer has been an employee of SIS since 1998 and is currently the Technical Team Leader and Advisor-Unconventional Reservoirs. His responsibilities include reserves evaluation, acquisition and divestiture analysis, unconventional reservoir analysis, and underground gas storage evaluation. Mr. Boyer graduated with a Bachelor of Science degree in Geological Sciences from The Pennsylvania State University in 1976; he is a registered Professional Geologist in the Commonwealth of Pennsylvania (No. PG004509), a Certified Petroleum Geologist of the American Association of Petroleum Geologists (No. 5733), and is a member in good standing of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, the American Association of Petroleum Geologists, and the Society for Mining, Metallurgy, and Exploration.

The reserves estimates as of December 31, 2017 and 2016 shown herein are based upon evaluations prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Steven W. Jansen and Mr. Edward C. Roy III. Mr. Jansen, a Licensed Professional Engineer in the State of Texas (No. 112973), has been practicing consulting petroleum engineering at NSAI since 2011 and has over 4 years of prior industry experience. He graduated from Kansas State University in 2007 with a Bachelor of Science Degree in Chemical Engineering. Mr. Roy, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 2364), has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. He graduated from Texas Christian University in 1992 with a Bachelor of Science Degree in Geology and from Texas A&M University in 1998 with a Master of Science Degree in Geology. 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; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines

*Estimation of Proved Reserves.* Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2018, 2017, and 2016 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties.

To estimate economically recoverable proved reserves and related future net cash flows, SIS considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

*Summary of Natural Gas, NGLs and Oil Reserves.* The following table presents our estimated net proved natural gas, NGLs and oil reserves as of December 31, 2018, based on the proved reserve report prepared by SIS, our independent petroleum engineers for the year ended December 31, 2018, and as of December 31, 2017 and 2016, based on the proved reserve reports prepared by NSAI, our independent petroleum engineers for the years ended December 31, 2017 and 2016, and such proved reserve reports have been prepared in accordance with the rules and regulations of the SEC. Our estimated proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December for the years 2018, 2017, and 2016. For oil and NGLs volumes, the average WTI spot price of $65.56 per barrel for December 31, 2018, $51.34 per barrel for December 31, 2017 and $42.75 per barrel for December 31, 2016, has been adjusted by property group for quality, transportation fees and regional price differentials. For gas volumes, the average NYMEX Henry Hub spot price of $3.10 per MMBtu for December 31, 2018, $2.98 per MMBtu for December 31, 2017 and $2.48 per MMBtu for December 31, 2016 has been adjusted by property group for energy content, transportation fees and regional price differentials. All prices are held constant throughout the lives of the properties. All of our proved reserves are located in the United States. Copies of the proved reserve reports as of December 31, 2018 prepared by SIS and December 31, 2017 and 2016 prepared by NSAI with respect to our properties are included as exhibits to this Annual Report. Our estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency other than the SEC.

| | 2018 | 2017 | 2016 |
|---|---|---|---|
| **Proved Developed Reserves:** | | | |
| Natural gas (Bcf) | 501.0 | 334.6 | 226.1 |
| NGLs (MBbls) | 20,213.8 | 13,782.9 | 7,520.0 |
| Oil (MBbls) | 8,058.7 | 6,449.6 | 4,439.5 |
| Combined (Bcfe) | 670.7 | 456.0 | 297.8 |
| **Proved Undeveloped Reserves:** | | | |
| Natural gas (Bcf) | 1,030.2 | 755.5 | 160.4 |
| NGLs (MBbls) | 14,517.2 | 28,147.7 | 1,155.5 |
| Oil (MBbls) | 12,793.4 | 13,031.2 | 718.1 |
| Combined (Bcfe) | 1,194.1 | 1,002.6 | 171.6 |
| **Proved Reserves:** | | | |
| Natural gas (Bcf) | 1,531.2 | 1,090.1 | 386.4 |
| NGLs (MBbls) | 34,730.9 | 41,930.6 | 8,675.5 |
| Oil (MBbls) | 20,852.1 | 19,480.8 | 5,157.7 |
| Combined (Bcfe) | 1,864.7 | 1,458.6 | 469.4 |

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of natural gas, NGLs and oil that are ultimately recovered. Estimates of economically recoverable natural gas, NGLs and oil and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read "Item 1A. Risk Factors" appearing elsewhere in this Annual Report.

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" and the proved reserve reports as of December 31, 2018, 2017, and 2016, which are included as exhibits to this Annual Report.

***Proved Reserves Additions and Revisions***

To maintain and grow production and cash flow, we must continue to develop existing proved reserves and locate or acquire new natural gas, NGLs and oil reserves. The following is a discussion of net proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

| | Natural Gas (Bcf) | NGLs (MBbls) | Oil (MBbls) | Total (Bcfe) |
|---|---|---|---|---|
| **Proved Reserves:** | | | | |
| **December 31, 2015** | **274.1** | **7,758.7** | **4,693.1** | **348.8** |
| Reserve revisions | (0.1) | 1,273.7 | 1,196.8 | 14.8 |
| Extensions and discoveries | 175.4 | 2,156.0 | 1,300.2 | 196.1 |
| Acquisitions | 3.8 | 24.8 | 15.1 | 4.1 |
| Divestitures | (5.9) | (91.5) | (703.7) | (10.7) |
| Production | (60.9) | (2,446.2) | (1,343.8) | (83.7) |
| **December 31, 2016** | **386.4** | **8,675.5** | **5,157.7** | **469.4** |
| Reserve revisions | 515.1 | 20,327.3 | 9,746.8 | 695.6 |
| Extensions and discoveries | 274.4 | 15,598.8 | 6,192.9 | 405.1 |
| Acquisitions | 1.6 | 42.6 | 5.8 | 1.9 |
| Production | (87.4) | (2,713.6) | (1,622.4) | (113.4) |
| **December 31, 2017** | **1,090.1** | **41,930.6** | **19,480.8** | **1,458.6** |
| Reserve revisions | 5.6 | (8,307.5) | 231.2 | (42.8) |
| Extensions and discoveries | 515.8 | 4,059.4 | 2,995.7 | 558.1 |
| Acquisitions | 9.9 | 551.4 | 522.2 | 16.3 |
| Divestitures | (0.2) | — | — | (0.2) |
| Production | (90.0) | (3,503.0) | (2,377.8) | (125.3) |
| **December 31, 2018** | **1,531.2** | **34,730.9** | **20,852.1** | **1,864.7** |

During the year ended December 31, 2018, we increased proved reserves by 406.1 Bcfe compared to the year ended December 31, 2017, primarily through extensions, performance revisions and acquisitions. This increase in proved reserves was comprised of 558.1 Bcfe of extensions and 16.3 Bcfe of acquisitions. The increase was offset by 125.3 Bcfe of production, 42.8 Bcfe of revisions and 0.2 Bcfe from the divestiture of one non-operated producing well. The revisions consisted of positive adjustments due to increased SEC pricing and differentials of 21.8 Bcfe, a positive performance revision of 67.5 Bcfe primarily due to well performance adjustments and a negative revision of 132.1 Bcfe due to changes in well spacing and field development.

***Future Net Cash Flows.*** At December 31, 2018, 2017, and 2016, the standardized measure of estimated future net cash flows after income taxes from our proved reserves was $1,329.3 million, $729.7 million and $206.0 million, respectively. At December 31, 2018, 2017, and 2016, the PV-10 value of estimated future net cash flows before income taxes from our proved reserves was $1,366.7 million, $729.7 million and $206.0 million, respectively. These PV-10 values were calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves.

The following table sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV-10) and the present value of those net cash flows after income tax (standardized measure):

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2018 | 2017 | 2016 |
| Future net cash flows | $2,909,969 | $1,538,529 | $ 300,430 |
| Present value of future net cash flows: | | | |
| Before income tax (PV-10) | $1,366,655 | $ 729,686 | $ 205,981 |
| Income taxes | (37,345) | — | — |
| After income tax (standardized measure) | $1,329,310 | $ 729,686 | $ 205,981 |

PV-10 is a non-GAAP financial measure and generally differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor standardized measure represents an estimate of the fair market value of our oil and natural gas properties. We, and others, in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. We believe that the presentation of the pre-tax PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our reserves prior to taking into account corporate income taxes and our current tax structure.

***Proved Undeveloped Reserves (PUDs)***

As of December 31, 2018, our proved undeveloped reserves were comprised of 12,793.4 MBbls of oil, 1,030.2 Bcf of natural gas and 14,517.2 MBbls of NGLs, for a total of 1,194.1 Bcfe. As of December 31, 2017, our proved undeveloped reserves were comprised of 13,031.2 MBbls of oil, 755.5 Bcf of natural gas and 28,147.7 MBbls of NGLs, for a total of 1,002.6 Bcfe. As of December 31, 2016, our proved undeveloped reserves were comprised of 718.1 MBbls of oil, 160.4 Bcf of natural gas and 1,155.5 MBbls of NGLs, for a total of 171.6 Bcfe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs during 2016, 2017, and 2018 (in Bcfe):

| | |
|---|---|
| **Balance, December 31, 2015** | **70.3** |
| Reserve revisions[1] | (14.2) |
| Acquisitions | 3.6 |
| Extensions and discoveries | 111.9 |
| **Balance, December 31, 2016** | **171.6** |
| Reserve revisions[2] | 528.5 |
| Acquisitions | 1.3 |
| Extensions and discoveries | 391.2 |
| Transfers to proved developed | (90.0) |
| **Balance, December 31, 2017** | **1,002.6** |
| Reserve revisions[3] | (101.8) |
| Acquisitions | 11.6 |
| Extensions and discoveries | 409.8 |
| Transfers to proved developed | (128.1) |
| **Balance, December 31, 2018** | **1,194.1** |

(1) Revisions to previous estimates are comprised of 16.6 Bcfe of positive technical revisions primarily due to well performance, 20.2 Bcfe of negative revisions related to pricing and differential changes, and negative revisions of 10.6 Bcfe due to economic locations that the Company no longer expects to develop within five years of initial classification.

(2) Revisions to previous estimates are comprised of 91.1 Bcfe of negative technical revisions primarily due to well performance, 620.6 Bcfe of positive revisions related to pricing and differential changes, and negative revisions of 1.0 Bcfe due to expense assumption changes.
(3) Revisions to previous estimates are comprised of 22.3 Bcfe of positive revisions primarily due to well performance, 8.0 Bcfe of positive revisions related to pricing and differential changes, and negative revisions of 132.1 Bcfe due to changes in well spacing assumptions.

During the year ended December 31, 2018, we converted approximately 128.1 Bcfe, or 13% of our proved undeveloped reserves as of December 31, 2017, to proved developed reserves at a capital cost of approximately $65 million. Estimated future development costs relating to the development of our proved undeveloped reserves as of December 31, 2018 are approximately $816 million over the next five years. All PUD drilling locations are scheduled to be converted to proved developed within five years of initial disclosure, with more than 75% of the future development costs expected to be spent in the next three years.

The development plan is formulated by our operations department and reviewed by the reserves committee and senior management. This plan is frequently reviewed to ensure all capital is allocated to the wells that have the highest rate of return and optimal development profile within the undrilled well inventory. This process may cause wells that were previously planned to be developed within five years to be rescheduled beyond five years and therefore no longer included as proved undeveloped wells in future filings.

***Production and Price History***

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| **Total production volumes[(1)]:** | | | |
| Natural gas (MMcf) | 89,965.7 | 87,404.2 | 60,921.9 |
| NGLs (MBbls) | 3,503.1 | 2,713.7 | 2,446.2 |
| Oil (MBbls) | 2,378.0 | 1,622.4 | 1,343.8 |
| Combined (Mmcfe) | 125,252.3 | 113,420.8 | 83,661.9 |
| **Average daily production volumes[(1)]:** | | | |
| Natural gas (Mcf/d) | 246,481 | 239,464 | 166,453 |
| NGLs (Bbls/d) | 9,598 | 7,435 | 6,684 |
| Oil (Bbls/d) | 6,515 | 4,445 | 3,672 |
| Combined (Mcfe/d) | 343,159 | 310,744 | 228,589 |
| **Average Realized Price (including cash settled derivatives and firm transportation):** | | | |
| Natural gas ($/Mcf) | $ 2.41 | $ 2.34 | $ 2.19 |
| NGLs ($/Bbl) | 24.32 | 21.96 | 15.55 |
| Oil ($/Bbl) | 50.47 | 46.14 | 44.66 |
| Combined ($/Mcfe) | $ 3.37 | $ 2.99 | $ 2.76 |
| **Expenses (per Mcfe):** | | | |
| Lease operating | $ 0.23 | $ 0.18 | $ 0.11 |
| Transportation, gathering and compression | 1.10 | 1.10 | 1.30 |
| Production, severance and ad valorem taxes | 0.08 | 0.07 | 0.09 |
| Depreciation, depletion and amortization | 1.07 | 1.05 | 1.11 |
| General and administrative | 0.35 | 0.39 | 0.47 |

(1) As of December 31, 2018, approximately 97% of our production and approximately 88% of our proved reserves are from the Utica Shale.

*Developed and Undeveloped Acreage*

The following table sets forth information as of December 31, 2018 relating to our leasehold acreage. Developed acres are acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

| | Developed Acreage | | Undeveloped Acreage | | Total Acreage | |
|---|---|---|---|---|---|---|
| **Area** | **Gross** | **Net[(1)]** | **Gross** | **Net[(1)]** | **Gross** | **Net[(1)]** |
| Ohio | 191,116 | 147,601 | 66,140 | 48,097 | 257,256 | 195,698 |
| Pennsylvania | 13,287 | 11,865 | 36,140 | 33,276 | 49,427 | 45,141 |
| Total | 204,403 | 159,466 | 102,280 | 81,373 | 306,683 | 240,839 |

(1) Fossil Creek owns a right to participate for a 12.5% working interest in approximately 117 gross acres within our area of mutual interest with Antero Resources Corporation ("Antero Resources"). In calculating our net acreage, we have assumed that Fossil Creek will elect to participate in all wells in which they have a right to participate for their full interest and have deducted this 12.5% working interest from our net acreage where applicable.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms, although approximately 64% of our leases in the Utica Core Area have a 3-5 year extension at our option. The following table sets forth the total gross and net undeveloped acres as of December 31, 2018 that will expire over the next five years unless operations have commenced on the leasehold acreage or lands pooled therewith have been established prior to such date, in which event the lease will remain in effect until the cessation of production in commercial quantities:

| Year Ending December 31, | Gross Acres | Net Acres |
|---|---|---|
| 2019 | 28,848 | 24,610 |
| 2020 | 14,161 | 12,840 |
| 2021 | 11,871 | 10,445 |
| 2022 | 8,128 | 4,336 |
| 2023 and beyond | 20,141 | 17,264 |

In 2019, we expect to incur approximately $21 million related to delay rentals and lease extensions related to acreage that would otherwise expire during 2019.

*Drilling Results*

The following table sets forth information with respect to the number of wells completed during the years indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

| | 2018 | | 2017 | | 2016 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| **Development Wells:** | | | | | | |
| Productive | 30 | 17.6 | 25 | 22.2 | 22 | 18.1 |
| Dry holes | — | — | — | — | — | — |
| **Exploratory Wells:** | | | | | | |
| Productive | — | — | — | — | — | — |
| Dry holes | — | — | — | — | — | — |
| **Total:** | | | | | | |
| Productive | 30 | 17.6 | 25 | 22.2 | 22 | 18.1 |
| Dry holes | — | — | — | — | — | — |

All of these productive wells are gas wells. Many of our gas wells also produce oil, condensate and NGLs. As of December 31, 2018, we had 16 gross (9.9 net) wells in the process of drilling, completing or shut in awaiting infrastructure that are not reflected in the above table.

**Operations**

*General*

As of December 31, 2018, we operated approximately 94% of our proved reserves. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

*Major Customers*

For the year ended December 31, 2018, sales to Marathon represented approximately 25% of our total sales. For the year ended December 31, 2017, sales to Emera Energy Services, Inc. ("Emera Energy Services") and Marathon represented approximately 17% and 10% of our total sales, respectively. For the year ended December 31, 2016, sales to Sequent Energy Management, L.P. ("Sequent Energy Management"), EnLink Midstream, Antero Resources and Concord Energy LLC ("Concord Energy") represented approximately 20%, 17%, 14%, and 12% of our total sales, respectively. Although a substantial portion of production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business, as other customers or markets would be accessible to us.

*Title to Properties*

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often-cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;

- obligations or duties under applicable laws;
- development obligations under natural gas leases;
- net profits interests;
- mortgages by a lessor; or
- rights of way or easements held by third parties such as utilities.

*Seasonality*

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, some natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

*Competition*

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

**Emerging Growth Company Status**

We are an “emerging growth company” as defined in the Jumpstart Our Business Startups Act, or the JOBS Act. For as long as we are an emerging growth company, unlike other public companies that are not emerging growth companies under the JOBS Act, we are not required to, among other things:

- provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- provide certain disclosure regarding executive compensation required of larger public companies or hold stockholder advisory votes on executive compensation as required by the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act; or
- obtain stockholder approval of any golden parachute payments not previously approved.

We will cease to be an “emerging growth company” upon the earliest of:

- the last day of the fiscal year in which we have $1.07 billion or more in annual revenues;
- the date on which we become a “large accelerated filer” (the fiscal year end on which the total market value of our common equity securities held by non-affiliates is $700.0 million or more as of June 30);
- the date on which we issue more than $1.0 billion of non-convertible debt over a 3-year period; or
- the last day of the fiscal year following the 5th anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, or the Securities Act, for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period, and as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

**Regulation of the Oil and Natural Gas Industry**

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing natural gas and oil properties have statutory provisions regulating the exploration for and production of natural gas and oil, 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 abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

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. Although we believe that we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict our future ability to comply with applicable law and regulations or the future costs or impact of compliance.

***Regulation of Production of Natural Gas and Oil***

The production of natural gas and oil is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill; although in some cases, we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas, NGLs and oil within its jurisdiction.

We own interests in properties located onshore in two U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas. The failure to comply with these rules and regulations can result in substantial penalties.

### *Regulation of Transportation and Sales of Natural Gas*

Historically, the transportation (including storage services) and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily the Federal Energy Regulatory Commission, or FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce and the revenues we receive for sales of our natural gas.

FERC's current policies allow for the sale of natural gas by producers at market-based prices. However, Congress could enact price controls in the future. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by FERC. In some limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The Energy Policy Act of 2005, or the EPAct 2005, among other matters, amended the NGA to add an anti-manipulation provision, which makes it unlawful for any entity, directly or indirectly, to use or employ, in connection with the purchase or sale of natural gas or the purchase of natural gas transportation services subject to FERC jurisdiction, any manipulative or deceptive device or contrivance of such rules and regulations as FERC may prescribe as necessary in the public interest or for the protection of natural gas ratepayers. Furthermore, EPAct 2005 provides FERC with additional civil penalty authority. The EPAct 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the Natural Gas Policy Act, or NGPA, from $5,000 per violation per day to $1,000,000 per violation per day. These civil penalty amounts under the NGA and NGPA have been adjusted in accordance with the Federal Civil Penalties Inflation Adjustment Act of 1990, as amended by the Federal Civil Penalties Inflation Adjustment Improvements Act of 2015, from $1,000,000 per violation per day to $1,269,500 per violation per day, effective February 1, 2019.

On January 19, 2006, FERC issued Order No. 670 to implement the anti-manipulation provision of the EPAct 2005. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made, in light of the circumstances under which they were made, not misleading; or (3) engage in any act, practice or course of business that operates, or would operate, as a fraud or deceit upon any entity. The anti-manipulation rule applies to "any entity", including otherwise non-jurisdictional entities, and may include activities that relate to intrastate or other non-jurisdictional sales or gathering, to the extent such activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting. Reporting required under Order 704 is considered to constitute an activity conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction.

We cannot reliably predict whether FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts and new proposals and proceedings are likely to arise. The natural gas industry historically has been very heavily regulated and changing conditions and experience has led to changes in such regulation. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other, similarly situated, natural gas producers.

Gathering service is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which can increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Section 1(b) of the NGA excludes natural gas gathering facilities from regulation by FERC under the NGA. Further, an entity is not subject to regulation under NGA by FERC as a "natural gas company" solely by virtue of such entity owning or operating such facilities. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to determine that the owner/operator of such facilities is not subject to regulation as a natural gas company under the NGA. However, FERC orders may affect the distinction between FERC-regulated transmission services and federally unregulated gathering services, which is the subject of ongoing litigation. Furthermore, Congress has discretion to revise the jurisdictional line. Consequently, the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our sales of natural gas are also subject to certain requirements under the Commodity Exchange Act, or CEA, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered, false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

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

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

**Regulation of Environmental and Occupational Safety and Health Matters**

***General***

Our operations are subject to numerous federal, regional, state, local, and other laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, the Resource Conservation and Recovery Act, or RCRA, the Clean Water Act, or the CWA, and the Clean Air Act, or the CAA. These laws and regulations, along with state analogs, govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. In jurisdictions which allow them, direct voter initiatives seeking to restrict oil and gas development could result in similar impacts.

In addition, public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, the EPA's National Compliance Initiatives include "Ensuring Energy Extraction Activities Comply with Environmental Laws." The EPA proposes to retain this category as a National Compliance Initiative for fiscal years 2020 through 2023. According to the EPA's website, the EPA proposes to focus on significant public health and environmental problems throughout the oil and gas sector, with a focus on volatile organic compound emissions that have a substantial impact on air quality and that may adversely affect vulnerable populations or an area's Clean Air Act attainment status. This initiative could involve a large-scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Noncompliance could also result in an increase in capital expenditures or reduced earnings and hurt our ability to compete in the marketplace. Accidental releases or spills may occur in the course of our operations, and we cannot be sure that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

***The Safe Drinking Water Act and the Underground Injection Control Program***

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act, or the SDWA, over hydraulic fracturing activities involving the use of diesel fuel. From time to time, however, Congress has proposed legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of all hydraulic fracturing activities, as well as to require disclosure of the chemical constituents of the fluids used in the fracturing process. Scrutiny of hydraulic fracturing activities by the EPA continues in other ways, with the EPA having completed a final report for a multi-year study of the potential environmental impacts of hydraulic fracturing. In addition, in June 2016, the EPA published final regulations under the CWA for wastewater discharges associated with unconventional oil and natural gas resources, such as low permeability and porosity formations. Moreover, on March 20, 2015, the U.S. Department of the Interior finalized updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. The Department of the Interior has also finalized rules to minimize venting and flaring from wells on federal lands. Although the Department of the Interior hydraulic fracturing rule has been rescinded and the venting and flaring rule has been replaced with a less stringent version, the original rules could be reinstated through litigation, which could result in material compliance obligations. Other governmental agencies, including the United States Department of Energy have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. In Ohio, the Department of Natural Resources finalized new horizontal well site construction requirements on July 6, 2015. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless regulations can be expected to become stricter in the future, and, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

### *Hazardous Substances and Wastes*

CERCLA, also known as the “Superfund law,” imposes cleanup obligations, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported, disposed, or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA and any state analogs may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file corresponding common law claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While petroleum and crude oil fractions are not considered hazardous substances under CERCLA and its analog because of the so-called “petroleum exclusion,” adulterated petroleum products containing other hazardous substances have been treated as hazardous substances in the past.

The RCRA regulates the generation and disposal of solid wastes and hazardous wastes. The RCRA specifically excludes from the definition of hazardous waste “drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy.” These materials are currently regulated as non-hazardous solid wastes. However, legislation has been proposed from time to time that could reclassify certain natural gas and oil exploration and production wastes as “hazardous wastes,” which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, some ordinary industrial wastes that we generate, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous wastes.

In addition, current and future regulations governing the handling and disposal of Naturally Occurring Radioactive Materials, or NORM, may affect our operations. For example, the Ohio Department of Natural Resources has asked operators to identify technologically enhanced NORM, or TENORM, in their processes, such as hydraulic fracturing sand, recycled drilling mud, and spent tank bottoms. Local landfills only accept such waste when it meets their TENORM standards. As a result, we may have to locate out-of-state landfills to accept TENORM waste from time to time, potentially increasing our disposal costs.

Some of our leases may have had prior owners who commenced exploration and production of natural gas and oil operations on these sites. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties may have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the RCRA, and/or analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

### *Waste Discharges*

The CWA and its state analog impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

### *Air Emissions*

The CAA and its state analog and regulations restrict the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. On April 17, 2012, the EPA also approved final rules that established air emission controls for oil and natural gas production and natural gas processing operations. These rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through reduced emission (or "green") completions, or flaring where green completions are not feasible. The rules also established specific requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas-processing plants, and certain other equipment. In May 2016, the EPA finalized amendments that expand the requirements of the 2012 rule to methane emissions and air emissions associated with hydraulic fracturing operations for oil wells. The EPA is continuing to consider other aspects of the new rules and may propose additional amendments. In addition, the U.S. Department of Interior finalized rules to reduce venting and flaring from oil and natural gas operations located on federal lands. In September of 2018, the Department of the Interior decreased the stringency of the venting and flaring rules; however, the replacement rule is under legal challenge and could be reinstated. If reinstated, the original rule may require a number of modifications to our own operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us and our customers, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

### *Oil Pollution Act*

The Oil Pollution Act of 1990, or the OPA, and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

### *National Environmental Policy Act*

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or the NEPA. The NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments, which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. The NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

### *Endangered Species Act and Migratory Bird Treaty Act*

The Endangered Species Act, or the ESA, and similar applicable state legislation restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Moreover, as a result of a settlement approved by the United States District Court for the District of Columbia in September 2011, the United States Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. For example, regulations designed to protect the Indiana bat (Myotis soldalis), which is an endangered species protected by the ESA and similar state legislation, restrict or increase the cost of our operations by, among other things, limiting our ability to clear trees to establish rights of way or pad locations on some of our acreage during certain periods of the year. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds we believe that we are in substantial compliance with the ESA, similar applicable state legislation and the Migratory Bird Treaty Act, and we are not aware of any proposed ESA listings that will materially affect our operations. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

#### *Worker Safety*

The Occupational Safety and Health Act, or the OSHA, and any analogous state law regulate the protection of the safety and health of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

### Employees

As of December 31, 2018, we had 159 full-time employees. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We utilize the services of independent contractors to perform various field and other services.

### Corporate Information

Our principal executive offices are located at 122 West John Carpenter Freeway, Suite 300, Irving, Texas 75039, and our telephone number is (469) 444-1647. Our website is *www.montageresources.com*. We expect to make our periodic reports and other information filed with, or furnished to, the SEC, available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with, or furnished to, the SEC. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at *www.sec.gov*. The information on, or otherwise accessible through, our website or any other website does not constitute a part of this Annual Report.

## Item 1A. RISK FACTORS

*Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report, actually occur, our business, financial condition or results of operations could suffer. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect our company.*

### Risks Related to Our Business

***Natural gas, NGLs and oil prices have been volatile and have declined from recent historical highs. If commodity prices remain depressed for a lengthy period of time or experience a further substantial or extended decline, our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments may be adversely affected.***

The prices we receive for our natural gas, NGLs and oil production heavily influence our revenue, operating results profitability, access to capital, future rate of growth and carrying value of our properties. Natural gas, NGLs and oil are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities markets have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide and regional economic conditions impacting the global supply of and demand for natural gas, NGLs and oil;
- the price and quantity of imports of foreign natural gas, including liquefied natural gas, foreign oil and refined products;
- the price and quantity of exported domestic crude oil, natural gas, including liquefied natural gas, NGLs and refined products;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indexes in the areas in which we operate and expectations about future commodity prices;
- the actions of the Organization of the Petroleum Exporting Countries;
- the proximity, capacity, cost and availability of gathering and transportation facilities, and other factors that result in differentials to benchmark prices;
- the cost of exploring for, developing, producing and transporting reserves;
- speculative trading in natural gas and crude oil derivative contracts;
- risks associated with operating drilling rigs;
- increased end-user conservation or conversion of alternative fuels;
- the price and availability of competitors’ supplies of natural gas, NGLs, oil and alternative fuels;
- localized and global supply and demand fundamentals and transportation availability;
- adverse or severe weather conditions and other natural disasters;
- technological advances affecting energy consumption and production; and
- domestic, local and foreign governmental regulation and taxes.

In addition, substantially all of our natural gas production and oil production is sold to purchasers under contracts with market-based prices based on NYMEX Henry Hub prices and WTI prices, respectively. The actual prices realized from the sale of natural gas and oil differ from the quoted NYMEX Henry Hub and WTI prices as a result of location differentials. Location differentials to NYMEX Henry Hub and WTI prices, also known as basis differential, result from variances in regional natural gas and oil prices as compared to NYMEX Henry Hub and WTI prices due to regional supply and demand factors. We have experienced, and expect to continue to experience, differentials to NYMEX Henry Hub and WTI prices, which may be material and could reduce the price we receive for these products relative to these benchmarks.

Lower commodity prices and negative increases in our differentials have reduced, and we expect will continue to reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, or at all, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices and negative differentials have also caused a significant portion of our development and exploration projects to become uneconomic, which may result in our having to make significant downward adjustments to our reserves. As a result, if commodity prices continue to remain depressed for a lengthy period of time or experience a further substantial or extended decline, or if our negative differentials increase, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures may be materially adversely affected.

***Commodity prices have declined substantially from historic highs and may remain depressed for the foreseeable future. If commodity prices continue to remain depressed, we may be required to write down the value of our oil and natural gas properties, some of our undeveloped locations may no longer be economically viable and the value of our estimated proved reserves could be reduced materially.***

During the eight years prior to December 31, 2018, natural gas prices at Henry Hub have ranged from a high of $8.15 per MMBtu in 2014 to a low of $1.49 per MMBtu in 2016. On December 31, 2018, the Henry Hub spot market price of natural gas was $3.25 per MMBtu. The reduction in prices has been caused by many factors, including increases in natural gas production and reserves from unconventional (shale) reservoirs, without an offsetting increase in demand. In addition, oil prices have declined significantly since the second half of 2014. The price of WTI crude oil was $45.15 per barrel on December 31, 2018, which is a significant decline from $106.07 per barrel on June 30, 2014. This environment could cause the commodity prices for oil and natural gas to remain at currently depressed levels or to fall to lower levels. If commodity prices remain depressed for lengthy periods, we may be required to write down the value of our oil and natural gas properties, and some of our undeveloped locations may no longer be economically viable. For example, for the year ended December 31, 2018, we recorded an impairment charge on certain oil and gas properties of $27.6 million for unproved properties, primarily attributable to lower commodity prices, and we have recorded impairment charges in prior years for similar reasons. In addition, sustained low commodity prices will negatively impact the value of our estimated proved reserves, which will negatively affect the borrowing base under our revolving credit facility and reduce the amounts of cash we would otherwise have available to pay expenses and service any indebtedness that we may incur. In such a case, we may be required to sell assets or raise capital by issuing additional debt or equity in order to pay expenses and service indebtedness. Furthermore, the value of our assets, if sold, may not be sufficient to pay our expenses or service our indebtedness.

***If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.***

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. For example, for the year ended December 31, 2018, we recorded an impairment charge on certain oil and gas properties of $27.6 million for unproved properties, primarily attributable to lower commodity prices, and we have recorded impairment charges in prior years for similar reasons. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to further write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

***If commodity prices do not improve or worsen or if we are unable to increase our liquidity, we could experience ratings downgrades.***

If commodity prices do not improve or worsen or if we are unable to increase our liquidity, we could experience ratings downgrades. For example, in January 2016, Moody's downgraded our corporate family credit rating and the rating of our 8.875% senior unsecured notes due 2023 primarily due to the effect of high leverage, low natural gas prices and significant production curtailments on our ability to generate cash flow from operations. These ratings were subsequently upgraded by Moody's in July 2017. In the event of any future downgrade, certain of our service providers, including our pipeline providers, may require us to post collateral or provide other assurances of our ability to perform our obligations under our contracts with such providers, which would negatively affect our liquidity and the borrowing base under our revolving credit facility and, in turn, increase the risk of additional downgrades.

***The integration of BRMR into the Company may not be as successful as anticipated.***

The BRMR Merger involved numerous operational, strategic, financial, accounting, legal, tax and other risks, potential liabilities associated with the acquired businesses, and uncertainties related to design, operation and integration of BRMR's internal control over financial reporting. Difficulties or delays in integrating BRMR into the Company may result in the combined company performing differently than expected, in operational challenges or in the failure to realize anticipated expense-related efficiencies or other anticipated benefits of the BRMR Merger and could adversely affect the combined company's business, financial condition or results of operations. The Company's existing business could also be negatively impacted by the BRMR Merger. Potential difficulties or delays that may be encountered in the integration process include, among other factors:

- the inability to successfully integrate the businesses of BRMR into the Company in a manner that permits the combined company to achieve the full expense-related efficiencies and operational and other synergies anticipated from the BRMR Merger;
- complexities associated with managing the larger, more complex, integrated business;
- integrating personnel from the two companies and the loss of management personnel, key employees or skilled workers;
- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with the BRMR Merger, including one-time cash costs to integrate the two companies that may exceed the anticipated range of such one-time cash costs that the Company and BRMR estimated as of the date of the execution of the Merger Agreement;
- integrating relationships with customers, vendors and business partners;
- actual or perceived operational or other business challenges that may raise concerns by customers, vendors and business partners;
- performance shortfalls or damage to business relationships as a result of the diversion of management's attention caused by completing the BRMR Merger and integrating BRMR's operations into the Company; and
- the disruption of, or the loss of momentum in, each company's ongoing business or inconsistencies in standards, controls, procedures and policies.

***The combined company's results may suffer if it does not effectively manage its expanded operations following the BRMR Merger.***

The BRMR Merger closed on February 28, 2019, and the combined company's success will depend, in part, on its ability to manage its expansion, which poses numerous risks and uncertainties and challenges for management, including the need to integrate the operations and businesses of the Company and BRMR in an efficient and timely manner, to combine systems and management controls and to integrate relationships with customers, vendors and business partners. There can be no assurance that the combined company will be successful in these efforts.

***The combined company may fail to realize all of the anticipated benefits of the BRMR Merger.***

The success of the BRMR Merger will depend, in part, on the combined company's ability to realize the anticipated expense-related efficiencies and other anticipated benefits from combining the Company's and BRMR's businesses, including operational and other synergies that the Company and BRMR believe the combined company will achieve. The anticipated expense-related efficiencies and other anticipated benefits of the BRMR Merger may not be realized fully or at all, may take longer to realize than expected or could have other adverse effects that the Company and BRMR do not currently foresee. The integration process may, result in the loss of management personnel, key employees or skilled workers, the disruption of ongoing businesses or inconsistencies in standards, controls, procedures and policies. There could be potential unknown liabilities and unforeseen expenses associated with the BRMR Merger that were not discovered in the course of performing due diligence.

***Our development and exploration projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, or at all, which could lead to a decline in our oil and natural gas reserves.***

The oil and natural gas industry is capital intensive. We have made, and if commodity prices rebound, expect to continue to make, substantial capital expenditures for the development and acquisition of oil and natural gas reserves. We expect to fund our capital expenditures in 2019 and subsequent to 2019 with cash on hand, cash generated by our operations and financing activities, which may include borrowings under our revolving credit facility, proceeds from non-core asset sales, proceeds from our drilling joint venture, and issuances of debt or equity. If we do not have sufficient borrowing availability under our revolving credit facility due to the current commodity price environment or otherwise, we may seek alternate debt or equity financing options (including, subject to compliance with our debt agreements, the issuance of first lien notes or other priority lien obligations), to sell assets or to further reduce our capital expenditures. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas, NGLs and oil prices and differentials, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in realized natural gas, NGLs or oil prices from current levels has resulted in a decrease in our actual capital expenditures, which have negatively impacted, and may continue to negatively impact, our ability to grow production. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flows from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures and acquisitions.

Our cash flows from operations and access to capital are subject to a number of variables, including, without limitation, the following:

- our proved reserves;
- the volumes and types of hydrocarbons we are able to produce from existing and future wells;
- our access to, and the cost of accessing, end markets for our production;
- the prices at which our production is sold;
- our ability to acquire, locate and develop new reserves;
- the levels of our operating expenses; and
- our ability to borrow under our revolving credit facility and issue additional debt and equity securities.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower natural gas, NGLs or oil prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If our cash on hand, cash flows generated by our operations and available borrowings under our revolving credit facility are insufficient to meet our capital requirements, the failure to obtain additional financing could result in a further curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

***Changes in laws or government regulations regarding hydraulic fracturing could increase our costs of doing business, limit the areas in which we can operate and reduce our oil and natural gas production, which could adversely impact our business.***

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and additives under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. However, with increased public concern regarding the potential for hydraulic fracturing to adversely affect drinking water supplies or other environmental impacts, proposals have been made, and in many cases finalized, to enact federal, state and local legislation and regulations that would increase, or have increased, the regulatory burden imposed on hydraulic fracturing. For example, the U.S. Environmenal Protection Agency (the "EPA") issued regulations to control air emissions from oil and natural gas production and natural gas processing operations, then proposed and finalized additional air emissions regulations from oil and natural gas production and natural gas processing operations, completed a multi-year study examining the potential impacts of hydraulic fracturing on drinking water resources, established standards for wastewater discharges from oil and gas extraction activities and released an Advance Notice of Proposed Rulemaking to solicit public comment on potential chemical disclosure requirements. The U.S. Congress continues to consider amending the Safe Drinking Water Act to remove the exemption for hydraulic fracturing activities and to require disclosure of additives constituents of fluids used in the fracturing process. The Department of the Interior released final rules to regulate hydraulic fracturing activities on federal lands and to limit venting and flaring from production operations. Although the Department of the Interior hydraulic fracturing rules have been rescinded and the venting and flaring rule has been replaced with a less stringent version, both are the subject of litigation that could result in the prior version of such rules becoming effective and it is possible that amended or similar rules will be proposed and finalized. In addition, the United States has made commitments to reduce greenhouse gas emissions under the Paris Agreement, part of the United Nations Framework Convention on Climate Change, and President Obama and Prime Minister Trudeau of Canada announced a joint agreement to reduce methane emissions from existing oil and gas operations. The Trump administration has since notified the United Nations of its intent to withdraw from the Paris Agreement, but under the terms of the agreement the U.S. will remain a party until approximately August 2020.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly for us to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce our oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

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

Properties that we decide to drill that do not yield natural gas, NGLs or oil in commercially viable quantities will adversely affect our results of operations and financial condition. Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. If the wells in the process of being drilled and completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected. In addition, there is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas, NGLs or oil in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas, NGLs or oil will be present or, if present, whether natural gas, NGLs or oil will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;

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

***Hydrocarbon windows, phases or type curve areas have an inherent degree of variability and may change over time, and as a result, the available well data with respect to such windows, phases and type curve areas may not be indicative of the actual hydrocarbon composition for the windows, phases or type curve areas.***

Based upon the well data available to us, we have grouped the publicly disclosed Utica Shale wells within the Utica Core Area into several distinct hydrocarbon windows, phases or type curve areas in an effort to better understand the thermal maturation variability within the Utica Core Area. However, there is an inherent degree of variability within such hydrocarbon windows, phases or type curve areas. Additionally, the well data we have utilized is predominantly based upon initial production rate, Btu content, natural gas yields and condensate yields, which may change over time. As a result, the well data with respect to the windows, phases and type curve areas within the Utica Core Area may not be indicative of the actual hydrocarbon composition for the windows, phases or type curve areas, or may not be the hydrocarbon composition of the windows, phases or type curve areas at the time we drill. Due to such factors, the performance, Btu content and NGLs and/or condensate yields of our wells may be substantially less than we anticipate or substantially less than performance and yields of other operators in the Utica Core Area, which may materially adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

***We have been an early entrant into the Utica Core Area, which is an emerging play, and have also been an early entrant into the portion of the Marcellus Shale underlying our Marcellus Area. As a result, our expected well results in these areas are uncertain, and the value of our undeveloped acreage will decline if well results are unsuccessful.***

Our expected well results in the Utica Core Area and our Marcellus Area are more uncertain than well results in areas that are more developed and have a greater number of producing wells. As a result, our cost of drilling, completing and operating wells in the Utica Core Area and our Marcellus Area may be higher than initially expected, the ultimate production and reserves from these wells may be lower than initially expected and the value of our undeveloped acreage may decline. Additionally, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. We cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

***Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.***

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us, other oil and gas exploration and production companies and our service providers. Risks that we face while drilling include, but are not limited to, the following:

- drilling wells that are significantly longer and/or deeper than more conventional wells;
- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to, the following:

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

***Drilling for and producing natural gas, NGLs and oil are high-risk activities with many uncertainties that could result in a total loss of investment or otherwise adversely affect our business, financial condition and results of operations.***

Our future financial condition and results of operations will depend on the success of our development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable production or that we will not recover all or any portion of our investment in such wells.

Our decisions to purchase, explore or develop prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "Items 1 and 2. Business and Properties—Oil and Natural Gas Data." Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could materially reduce our borrowing capacity. In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including, without limitation, the following:

- compliance with regulatory requirements, including limitations resulting from wastewater disposal, discharge of greenhouse gases, and limitations on hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering and processing facilities or delays in construction of gathering and processing facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as blizzards and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- terrorist (including eco-terrorist) attacks targeting natural gas and oil related facilities and infrastructure;
- declines in natural gas, NGLs and oil prices;
- limited availability of financing at acceptable terms;
- title problems and well permit objections from coal operators; and
- limitations in the market for natural gas.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

***We have incurred losses from operations in a significant number of years since our inception and may do so in the future.***

Although we generated net income of $18.8 million and $8.5 million for the years ended December 31, 2018 and 2017, respectively, we incurred a net loss in each of the prior years since our inception. Our development of and participation in a large number of prospects has required, and if commodity prices rebound will require, substantial capital expenditures. The uncertainty and factors described throughout this “Risk Factors” section may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future, which could adversely affect the trading price of our common stock and our ability to fund our operations and fulfill our debt obligations.

***We may not be able to generate sufficient cash to service all of our indebtedness, including our senior unsecured notes, and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.***

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our revolving credit facility and our senior unsecured notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal of, or premium, if any, and interest on, our indebtedness when due.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, raise additional capital or restructure or refinance our indebtedness. Our ability to raise additional capital or restructure or refinance our indebtedness will depend on the condition of the credit, financial or other capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with covenants that could further restrict our business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness.

In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. The value of our assets, particularly in times of low or volatile commodity prices, may not be sufficient to satisfy our liquidity needs or to repay our indebtedness. Furthermore, the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes restrict our subsidiaries’ ability to dispose of assets and our subsidiaries’ use of the proceeds from any such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations and fund our operations.

As of December 31, 2018, we had approximately $543.0 million in total indebtedness, no senior secured indebtedness outstanding and approximately $165.5 million of available borrowing capacity under our revolving credit facility (after giving effect to approximately $27.0 million of outstanding letters of credit and $32.5 million of outstanding borrowings). On February 28, 2019, we amended and restated the credit agreement governing our revolving credit facility to, among other things, increase the borrowing base from $225 million to $375 million and extend the maturity date thereof to approximately five years after the closing of the BRMR Merger. Subsequent to December 31, 2018, we reduced our outstanding letters of credit to approximately $13.5 million. Further, we borrowed an incremental $85 million under our revolving credit facility, which reduced the available borrowing capacity under such facility to $244 million.

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

***Our producing properties are concentrated in the Appalachian Basin, which makes us vulnerable to risks associated with operating in one major geographic area.***

Our producing properties are geographically concentrated in the Appalachian Basin. At December 31, 2018, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages, weather related conditions or interruption of the processing or transportation of natural gas, NGLs or oil. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations. In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations, the existence of which could require coordination to avoid adverse impacts as a result of drilling and mining in close proximity. These restrictions on our operations, and any similar restrictions, can cause delays or interruptions or can prevent us from executing our business strategy, which could have a material adverse effect on our financial condition and results of operations.

Due to the concentrated nature of our portfolio of natural gas and oil properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

***We own non-operating interests in properties developed and operated by third parties, and as a result, we are unable to control the operation and profitability of such properties.***

We frequently participate as a non-operator in the drilling and completion of wells with third parties that exercise exclusive control over such operations. As a non-operator participant, we rely on the third party operating company to successfully operate these properties pursuant to joint operating agreements and other similar contractual arrangements.

As a non-operator participant in these operations, we may not be able to maximize the value associated with these properties in the manner we believe appropriate, or at all. For example, we cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third party operator's operational expertise and financial resources and ability to gain the approval of other participants in drilling wells will impact the timing and potential success of our drilling and development activities in a manner that we are unable to control. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our financial condition and results of operations.

***Our existing providers of gas gathering, processing and fractionation capacity may not be able to provide to us sufficient capacity for our production from the Utica Core Area, and as a result, we may be required to find alternative markets and gathering, processing or fractionation arrangements for our production from the Utica Core Area, which alternative arrangements may not be available on favorable terms, or at all.***

A significant portion of our Utica Core Area acreage position is dedicated to long-term firm gas gathering, processing and fractionation agreements with primary terms of approximately 13 years. These agreements give us priority service and capacity over non-firm parties that wish to utilize the gas processing and fractionation plants and gas gathering system. As a result of such dedications, a significant portion of our operated wet gas acreage is committed to Blue Racer for gathering, processing and fractionation. Additionally, a significant portion of our operated dry gas acreage is committed to Eureka Midstream for gathering and a significant portion of our operated wet gas acreage is committed to EnLink Midstream for condensate gathering and stabilization. While we believe we have reserved sufficient capacity at these plants and on such systems to gather, process, fractionate and stabilize all of our projected production associated with our proved resources and a significant portion of our projected production from the Utica Core Area, that capacity may not be sufficient to handle all of our production or the plants and systems may experience significant mechanical problems or delays in construction or become unavailable to us due to unforeseen circumstances. As a result, we may be required to find alternative markets and gathering, processing or fractionation arrangements for our production from the Utica Core Area that is committed under these agreements, and such alternative arrangements may only be available on less favorable terms, or not at all.

***We currently do not have agreements with providers of gas gathering, processing or fractionation capacity with respect to our production from our Marcellus Area, and we may not be able to enter into such agreements on favorable terms, or at all.***

We have not entered into any gas gathering, processing or fractionation agreements with respect to our production from a portion of our Marcellus Area. We may not be able to enter into any such agreements on favorable terms, or at all. Without such agreements, we may not receive priority service or capacity over third parties that utilize the same gas processing and fractionation plants and gas gathering systems. Our inability to obtain sufficient gas gathering, processing and fractionation capacity for our production from a portion of our Marcellus Area could negatively impact our cash flows, financial condition and results of operations and reduce the overall value of our assets within this area.

***Insufficient processing or takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas, NGLs and oil prices.***

The Appalachian Basin natural gas business environment has historically been characterized by periods in which production has surpassed local processing and takeaway capacity, resulting in substantial discounts in the price received by producers such as us. A significant portion of our production from the Utica Core Area is currently being transported on pipelines that, after including the cost of such transportation, will consistently or periodically experience a negative differential to NYMEX Henry Hub prices.

Significant portions of our contracted firm transportation capacity have not been put into service. To the extent such projects are delayed or cancelled and we are unable to secure additional long-term firm takeaway capacity on major pipelines that are in existence or currently under construction in our core operating area to accommodate our production and to manage basis differentials, it could have a material adverse effect on our financial condition and results of operations.

Oil and condensate produced in the Appalachian Basin has increased substantially. There is limited takeaway capacity for these products and our sales of these products are currently occurring, and we expect will continue to occur, at a discount to the benchmark WTI price. If our providers are unable to secure buyers for these products, it could have a material adverse effect on our financial condition and results of operations.

***We currently are and in the future expect to be party to contracts with third parties that include contractual minimums.***

We are currently party to and expect to continue to be party to service contracts with drilling rig companies that require us to make shortfall payments to such companies if our actual activity level falls below specified contractual minimum activity levels. Moreover, we have entered into service contracts, and in the future may enter into additional service contracts, such as firm pipeline transportation contracts with companies owning interstate pipelines, that require us or may require us to make shortfall payments if our actual throughput falls below specified contractual minimum volumes. For the year ended December 31, 2018, we incurred approximately $1.1 million in shortfall payments under such contracts. As such, we can provide no assurance that our activity levels will be sufficient to satisfy the minimum requirements under our drilling rig contracts or that our future volumes will be sufficient to satisfy the minimum requirements under any such firm transportation contracts. If we fail to satisfy the minimum activity levels or throughput requirements associated with such contracts, we would be obligated to make shortfall payments to our counterparties based on the difference between our actual activity levels and throughput volumes, respectively, and the contract minimums in each case. These differences and the associated shortfall payments could be significant and we may not be able to generate sufficient cash to cover those obligations, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing.

***Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.***

The credit agreement governing our revolving credit facility contains a number of significant covenants, including restrictive covenants that restrict our and our subsidiaries' ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- hedge future production;
- incur liens;
- change the nature of our business; and
- engage in certain other transactions without the prior consent of the lenders.

The indenture governing our senior unsecured notes contains similar restrictive covenants. In addition, the credit agreement governing our revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indenture governing our senior unsecured notes, may limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants of the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes.

A breach of any covenant in the credit agreement governing our revolving credit facility or the indenture governing our senior unsecured notes would result in a default under the applicable agreement after any applicable grace periods. A default, if not waived or cured, could result in acceleration of the indebtedness outstanding under the relevant agreement and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or obtain sufficient capital to refinance such indebtedness. Even if a refinancing were available, it may not be on terms that are acceptable to us. Moreover, an increased interest rate is also payable in connection with a default under the credit agreement governing our revolving credit facility and certain payment defaults under the indenture governing our senior unsecured notes.

***Any significant reduction in our borrowing base or reduction of lender commitments under our revolving credit facility, as a result of the periodic borrowing base redeterminations or otherwise, may negatively impact our ability to fund our capital expenditure plan.***

We expect to fund a portion of our capital expenditure plan through 2019 with future borrowings under our revolving credit facility. The credit agreement governing our revolving credit facility limits the amounts we can borrow under our revolving credit facility from time to time up to a specified maximum borrowing base amount or the aggregate amount of lender commitments, whichever is less. The lenders, in their sole discretion, will determine a borrowing base on a semi-annual basis based upon the loan value assigned to the proved reserves attributable to our oil and gas properties evaluated in our most recent reserve report(s). Our lenders may further request two additional unscheduled borrowing base redeterminations during each calendar year. Any increase in the borrowing base will require the consent of the lenders holding 95.0% (or 100.0% if there are fewer than three lenders at the time of determination) of the outstanding credit amounts, or if none are then outstanding, 95% of the commitments (provided that no lender's commitment may increase without its consent). Distinct from determinations of a borrowing base, each lender, in its sole discretion, will determine the maximum amount of loans it will commit to make under our revolving credit facility based, in part, on general economic considerations and its prevailing lending policies. Outstanding borrowings in excess of the lesser of the specified maximum borrowing base amount or the prevailing aggregate lender commitment must be repaid. If we fail to repay such excess borrowings on a timely basis, we must provide additional oil and gas properties as collateral to the extent necessary to eliminate the deficiency. As of December 31, 2018, the borrowing base under our revolving credit facility was $225 million with $32.5 million in outstanding borrowings under our revolving credit facility, resulting in borrowing availability of approximately $165.5 million (after giving effect to approximately $27.0 million of outstanding letters of credit). On February 28, 2019, we amended and restated the credit agreement governing our revolving credit facility to, among other things, increase the borrowing base from $225 million to $375 million and extend the maturity date thereof to approximately five years after the closing of the BRMR Merger. Subsequent to December 31, 2018, we reduced our outstanding letters of credit to approximately $13.5 million. Further, we borrowed an incremental $85 million under our revolving credit facility, which reduced the available borrowing capacity under such facility to $244 million.

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

We have made asset and business acquisitions in the past, including, most recently, the BRMR Merger, and we may continue to make acquisitions of assets or businesses in the future that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Further, the success of any completed acquisition, including the BRMR Merger, depends on our ability to integrate the acquired business effectively into our existing operations and such integration process may involve difficulties that require a disproportionate amount of our managerial and financial resources to resolve. We may also fail to realize the expected benefits of any completed acquisitions, and completed acquisitions may subject us to significant transaction costs, unknown liabilities, and/or other unanticipated expenses, such as litigation expenses.

In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate successfully the acquired businesses and assets into our existing operations or to minimize any unforeseen liabilities or operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes impose certain limitations on our ability to enter into mergers or combination transactions and to make investments. The credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes also limit our ability to incur certain indebtedness and liens, which could limit our ability to engage in acquisitions of businesses.

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

We have historically acquired assets and businesses that we feel complement our assets and business and may continue to do so in the future. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future natural gas, NGLs or oil prices and their applicable differentials;
- 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 capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis.

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including, without limitation, assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. As a substantial portion of our reserve estimates are made without the benefit of a lengthy production history, any significant variance from the above assumption could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated natural gas reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Reserve estimates for plays, such as the Utica Core Area and our Marcellus Area, where we predominately operate, that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. Less production history may contribute to less accurate estimates of reserves, future production rates and the timing of development expenditures. Estimated reserves may not be correlated to perforated lateral length or completion technique. Furthermore, the lack of operational history for horizontal wells in the Utica Core Area and our Marcellus Area may also contribute to the inaccuracy of future estimates of reserves and could result in our failing to achieve expected results in these plays. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates or management expectations would have a material adverse effect on our business, financial condition, results of operations and cash flows. Furthermore, given the amount of our total estimated proved reserves in relation to the amount of our outstanding debt obligations, the value of our assets may not be sufficient to satisfy our liquidity needs or to repay our indebtedness.

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

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas, NGLs and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, topographical constraints, lease expirations, the ability to form units, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, governmental regulation, the ability to pool or unitize our acreage with acreage leased to other operators and approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other identified drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. Further, some of the horizontal wells we intend to drill in the future may require unitization with adjacent leaseholds controlled by third parties. If these third parties are unwilling to unitize such leaseholds with ours, this may limit the total locations we can drill. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2018 after deducting wells that have been drilled or are in progress, we had identified approximately 90.2, 15.0, 77.6, 87.3 and 72.0 net undeveloped Dry Gas, Rich Gas, Condensate, Flat Castle and Marcellus Condensate locations, respectively. As a result of the limitations described above, including the recent significant declines in natural gas and oil prices, we may be unable to drill many of our identified drilling locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified drilling locations, see "Business—Our Properties."

***We have acreage that we must commence operations upon before lease expiration in order to hold the acreage by production. If we fail to drill sufficient wells to hold acreage we incur substantial lease renewal costs, or if renewal is not feasible, lose our lease and prospective drilling opportunities.***

Leases on our oil and natural gas properties typically have a primary term of 5 years, after which they expire unless, prior to expiration, we commence operations within the spacing units covering the undeveloped acres. As of December 31, 2018, we had leases representing approximately 28,848 gross (24,610 net) undeveloped acres scheduled to expire in 2019, 14,161 gross (12,840 net) undeveloped acres scheduled to expire in 2020, 11,871 gross (10,445 net) undeveloped acres scheduled to expire in 2021, 8,128 gross (4,336 net) undeveloped acres scheduled to expire in 2022, and 20,141 gross (17,264 net) undeveloped acres scheduled to expire in 2023 and beyond. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms, or at all. Moreover, many of our leases require lessor consent to create units larger than the leases currently permit, which may make it more difficult to hold our leases by production or optimally develop our leasehold position. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, natural gas, NGLs and oil prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, gathering systems and pipeline transportation constraints and regulatory approvals. In order to hold our current leases that are scheduled to expire in 2019 and 2020, we have deployed a strategy to convert our land extension payments into multi-year delay rental payments, which is designed to spread the costs beyond a single year. We cannot assure you that we will have the liquidity to execute on this strategy, that landowners will be willing to enter into this type of lease modification or that we will have the liquidity to otherwise deploy rigs when needed to hold this expiring acreage. Our reserves and future production, and therefore, our future cash flows and income, are highly dependent on successfully extending or developing our undeveloped leasehold acreage and the loss of any leases could materially adversely affect our ability to so develop such acreage.

***The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.***

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2018, 2017, and 2016, we based the discounted future net cash flows from our proved reserves on the 12-month first-day-of-the-month oil and natural gas average prices without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for natural gas, NGLs and oil;
- actual cost of development and production expenditures;
- the effect of derivative transactions;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. As a corporation, we are treated as a taxable entity for federal income tax purposes, and our income taxes are dependent on our taxable income. Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report, which could have a material effect on the value of our reserves.

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

Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due to the long history of land ownership in the area, resulting in extensive and complex chains of title. In the course of acquiring the rights to develop oil and natural gas, it is standard procedure for us and the lessor to execute a lease agreement with payment subject to title verification. In most cases, we incur the expense of retaining lawyers, title abstractors or landmen to verify the rightful owners of the oil and gas interests prior to payment of such lease bonus to the lessor. There is no certainty, however, that a lessor has valid title to its lease's oil and gas interests. In those cases, such leases are generally voided and payment is not remitted to the lessor. As such, title failures may result in fewer net acres to us. Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Accordingly, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we could suffer a financial loss or an impairment of our assets.

***The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.***

At December 31, 2018, we had 1,864.7 Bcfe of total estimated proved reserves, of which approximately 64% were classified as proved undeveloped. Our approximately 1,194.1 Bcfe of estimated proved undeveloped reserves will require an estimated $816 million of development capital over the next 5 years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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

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

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

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to natural gas, NGLs and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas, NGLs and oil. The impact of the changing demand for natural gas, NGLs and oil services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas and oil, we have entered into derivative instrument contracts for a significant portion of our natural gas, NGLs and oil production, including fixed-price swaps, basis swaps, collars and firm sales agreements. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

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

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract. Any default by a counterparty to these derivative contracts when they become due would have a material adverse effect on our financial condition and results of operations.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, which could also have an adverse effect on our financial condition.

***The inability of our significant customers to meet their obligations to us may adversely affect our financial results.***

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables ($24.8 million at December 31, 2018) and the sale of our natural gas and oil production ($94.1 million in receivables at December 31, 2018). Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells. For the year ended December 31, 2018, one customer, Marathon, accounted for approximately 25% of our revenues. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

***Our operating history is limited and as a result there is only limited historical financial and operating information available upon which to base an evaluation of our performance. Moreover, the historical financial and operating information included in this Annual Report may not be indicative of our future financial performance.***

Our operating history is limited and as a result there is only limited historical financial and operating information available upon which to base an evaluation of our performance. Moreover, the historical financial and operating information included in this Annual Report may not be indicative of our future financial performance. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Factors That Significantly Affect Comparability of Our Financial Condition and Results of Operations” for a description of recent developments and transactions that may affect the comparability of our historical financial condition and results of operations for the periods presented to future periods. There can be no assurance that we will operate profitably. If our current business strategy is not successful, and we are not able to operate profitably, investors may lose some or all of their investment.

***Our operations are subject to governmental laws and regulations, which may expose us to significant costs and liabilities that could exceed current expectations.***

Our operations are subject to various federal, state and local governmental regulations. Matters subject to regulation include wastewater disposal, the spacing of wells, unitization and pooling of properties and taxation. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations, primarily relating to protection of human health and the environment. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue for the foreseeable future. Please read “Items 1 and 2. Business and Properties—Regulation of the Oil and Natural Gas Industry” and “Items 1 and 2. Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters” for a description of the laws and regulations that affect us.

We make assumptions and develop expectations about possible expenditures based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change and new capital costs may be incurred to comply with such changes. In addition, new laws and regulations might adversely affect our operations and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions.

***Recent decisions by the Ohio Supreme Court interpreting the Ohio Dormant Mineral Act relating to preservation of mineral rights by surface owners could complicate title review, delay drilling activities and increase leasehold expenses with respect to some of our leasehold acreage in Ohio.***

On September 15, 2016, the Ohio Supreme Court issued a series of decisions relating to the Ohio Dormant Mineral Act, which we refer to as the ODMA. In the lead case, Corban v. Chesapeake Exploration L.L.C., the court concluded that the 1989 version of the ODMA did not transfer ownership of dormant mineral rights automatically, by operation of law. Instead, prior to 2006, surface owners were required to bring a quiet title action in order to establish abandonment of mineral rights. After June 30, 2006 (the effective date of the 2006 version of the ODMA), surface owners are required to follow the statutory notice and recording procedures enacted in 2006. As a result, going forward, it will be more difficult for a surface owner to achieve an abandonment of mineral rights as the Ohio Supreme Court held that the statutory notice and recording provisions of the 2006 version of the ODMA will apply. In addition, mineral interests that may previously have been believed to be automatically abandoned by operation of law will now be valid pursuant to the Ohio Supreme Court's rulings. Accordingly, these recent Ohio Supreme Court decisions may complicate title review, delay drilling activities and increase leasehold expenses with respect to our operations in Ohio where the majority of our acreage and producing properties are located, any of which could have an adverse effect on our results of operations and financial condition.

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

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to the handling of our products as they are gathered, transported, processed and stored, air emissions related to our operations, historical industry operations, and water and waste disposal practices. Joint and several strict liability may be incurred without regard to fault under some environmental laws and regulations, including the Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act, the Oil Pollution Act, and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of natural gas, oil and wastes on, under, or from our properties and facilities. Private parties may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate may be located near current or former third party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

We may be held responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

***Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water and water disposal options. Restrictions on the ability to obtain water or dispose of wastewater may impact our operations.***

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations.

In addition, various studies have identified potential links between increases in seismic activity and the injection/disposal of water associated with oil and natural gas production, which could result in the imposition of operational limits or closure of disposal wells in areas where such links are suspected. For example, the Ohio Department of Natural Resources (“ODNR”) adopted rules that, among other things, allow the ODNR to require submission of a seismic monitoring plan, and require continuous monitoring of injection and annulus pressures on new wells.

***We are subject to risks associated with climate change.***

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases (“GHGs”). The EPA has issued a series of GHG monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG, cap-and-trade programs. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives, but this is potentially subject to change if new or more stringent requirements are imposed. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce GHG emissions and in March 2016 President Obama and Prime Minister Trudeau of Canada announced a joint agreement to reduce methane emissions from existing oil and gas operations. Our business and our financial results could be adversely impacted to the extent that the United States implements any additional GHG regulations in accordance with such agreement. The Trump administration has since notified the United Nations of its intent to withdraw from the Paris Agreement, but under the terms of the agreement the U.S. will remain a party until approximately August 2020.

The costs that may be associated with the impacts of climate change and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, and the demand for and consumption of our products and services (due to changes in both costs and weather patterns). If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. At this time, however, it is not possible to estimate how future laws or regulations or climatic changes may impact our business.

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

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

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline or river contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines or processing facilities;
- personal injuries and death;
- natural disasters; and
- terrorist (including eco-terrorist) attacks targeting natural gas and oil related facilities and infrastructure.

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

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

In accordance with what we believe to be customary industry practice, we maintain insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any or all of the losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flows. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial condition. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are a large part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and cleanup costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the "occurrence" to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows.

***Market conditions or operational impediments may hinder our access to natural gas, NGLs or oil markets or delay our production.***

Market conditions or the unavailability of satisfactory natural gas, NGLs or oil transportation arrangements may hinder our access to markets or delay our production. The availability of a ready market for our production depends on a number of factors, including the demand for and supply of natural gas, NGLs or oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Because many of our operations are in an emerging play, much of this infrastructure is currently being built or is yet to be built, and we cannot assure you that it will be built on time or at all. Our failure to obtain such services on acceptable terms and concurrent with the completion of our wells could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGLs or oil pipeline or gathering system capacity. In addition, if quality specifications for the third party pipelines with which we connect change so as to restrict our ability to transport product, our access to markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

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

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Some of the rigs performing work for us do so on a well-by-well basis and can refuse to provide such services at the conclusion of drilling on the current well. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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

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

***The past success of our senior management with developing public and private natural gas and oil enterprises, and the expertise of our senior management in the acquisition, exploration and development of unconventional natural gas and oil properties does not guarantee our success or profitability.***

As described in this Annual Report, most of our executive officers and other key personnel, including our President and Chief Executive Officer, John Reinhart, our Executive Vice President and Chief Operating Officer, Oleg Tolmachev, our Executive Vice President and Chief Financial Officer, Michael Hodges, and our Executive Vice President, Resource Planning and Development, Matthew Rucker, have substantial past experience in the acquisition, exploration and development of unconventional natural gas and oil properties, including experience at Ascent Resources, LLC, Chesapeake Energy Corporation, PayRock Energy II, LLC, Ward Energy Partners, LLC, and Rex Energy Corporation. However, the past experience and success of our executive officers and other key personnel with respect to previous endeavors in the natural gas and oil industry is not a guarantee of our future success or profitability.

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

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel, including our President and Chief Executive Officer, John K. Reinhart, our Executive Vice President and Chief Operating Officer, Oleg Tolmachev, our Executive Vice President and Chief Financial Officer, Michael Hodges, our Executive Vice President, Resource Planning and Development, Matthew Rucker, and our Executive Vice President, Corporate Secretary and General Counsel, Paul M. Johnston, could have a material adverse effect on our business, financial condition and results of operations.

***Seasonal weather conditions and regulations intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in the areas where we operate.***

Natural gas and oil operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect certain species of wildlife. For example, we must comply with state and federal regulations aimed at protecting the Indiana and Northern Long-Eared bats, which have been listed as a protected species by both federal and state law, and those regulations restrict or increase the cost of our operations by, among other things, limiting our ability to clear trees to establish rights of way or pad locations on some of our acreage during certain periods of the year. See "Items 1 and 2. Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters—Endangered Species Act and Migratory Bird Treaty Act." Adverse seasonal weather conditions and wildlife regulations may limit our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. In addition, the designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration, development and production activities.

***Acts of terrorism (including eco-terrorism) could have a material adverse effect on our financial condition, results of operations and cash flows.***

Our assets and operations, and the assets and operations of our providers of gas gathering, processing, transportation and fractionation services, may be targets of terrorist activities (including eco-terrorist activities) that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport, market or distribute natural gas, NGLs and oil. Acts of terrorism, as well as events occurring in response to or in connection with acts of terrorism, could cause environmental and other repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, acts of terrorism, and the threat of such acts, could result in volatility in the prices for natural gas, NGLs and oil and could affect the markets for such commodities.

***Increases in interest rates could adversely affect our business.***

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

***The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could adversely affect our ability to use derivative instruments to hedge risks associated with our business.***

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) was enacted on July 21, 2010 and establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission (the “CFTC”) and the SEC to promulgate certain rules and regulations implementing the Dodd-Frank Act, with the CFTC responsible for the rules and regulations regarding derivatives of the type we may use to hedge certain risks. Although the CFTC has finalized most of its implementing regulations, others remain to be finalized and it is not possible at this time to predict when this will be accomplished. In addition, the CFTC and its staff regularly issue rule amendments and guidance, policy statements, and letters interpreting the derivatives provisions of the Dodd-Frank Act, the contents of which cannot be known in advance.

The Dodd-Frank Act enhanced the CFTC’s authority to establish rules and regulations setting position limits for certain futures and option contracts, including in the major energy markets, and, for the first time, swaps that are their economic equivalents. The CFTC’s initial position limits rules under the Dodd-Frank Act were vacated by the U.S. District Court for the District of Columbia in September 2012 before such rules took effect. However, the CFTC has proposed new rules that would place limits on positions in certain core futures, options and equivalent swaps contracts in certain physical commodities, subject to limited exceptions for certain bona fide hedging and other transactions. The CFTC has also adopted final rules regarding the aggregation of positions in determining compliance with federal position limits. While the position aggregation rules are final, the position limit rules themselves are not, and therefore the impact of those rules on our use of derivatives in commodities for which federal position limits would be imposed is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and execution on certain trading platforms. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing or trade execution. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, margin rules for uncleared swaps, adopted during the fourth quarter of 2016 by the CFTC and federal banking regulators and requiring the posting of collateral by swap dealers and certain other financial entities, could impact liquidity and therefore reduce our ability to execute hedges to reduce risk and protect cash flows. The margin rules are not in effect for all market participants, and therefore the impact of those provisions to us is uncertain.

The Dodd-Frank Act and regulations may have other effects, including requiring or causing the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which, among other impacts, could adversely affect our ability to plan for and fund capital expenditures.

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 physically settled instruments related to oil and natural gas. Our revenues could therefore be adversely affected to the extent that the Dodd-Frank Act and regulations contribute to lower commodity prices.

Any of these consequences could have a material adverse effect on us, our financial condition or our results of operations.

***Proposed changes to U.S. and state tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.***

We primarily operate in Ohio, Pennsylvania, and following the closing of the BRMR Merger, West Virginia. Legislation in these jurisdictions has been proposed from time to time that would impose or increase severance taxes on natural gas and oil extraction. For example, Ohio has previously considered, and, the Ohio Legislature continues to consider, proposals to increase the current severance tax imposed on production of natural gas or oil in Ohio. The Commonwealth of Pennsylvania requires an impact fee to be paid on all unconventional wells spud based on a price tier calculation for a period of 15 years. However, Pennsylvania's governor and legislature have continued to discuss the imposition of a state severance tax on the extraction of natural resources, including natural gas produced from the Marcellus, Upper Devonian, and Utica Shale formations, either in replacement of or in addition to the existing impact fee. If any legislation imposing or increasing severance taxes is enacted, or other similar changes occur that tax our production or reduce or eliminate deductions currently available with respect to natural gas and oil exploration and development, it could adversely affect our business, financial condition, results of operations and cash flows.

***Changes to state tax laws in response to recently enacted U.S. federal tax legislation or to impose new or increased taxes or fees on natural gas and oil extraction may result in an increase in the state taxes we pay.***

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

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

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

***Our ability to use our net operating loss and credit carryforwards to offset future taxable income may be subject to certain limitations.***

As of December 31, 2018, we estimate that we have available to offset future taxable income approximately $667 million of federal net operating loss carryforward. A substantial amount of this net operating loss carryforward was incurred prior to the effective date of the new limitation on utilization of net operating losses imposed by the Tax Cuts and Jobs Act, and portions of this net operating loss carryforward will expire each year from 2034 to 2037. Our ability to utilize this net operating loss carryforward is dependent upon our ability to generate taxable income in future periods and may be limited due to restrictions imposed on the utilization of net operating losses under U.S. federal income tax laws after an "ownership change."

Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), imposes restrictions on the use of a corporation's net operating losses, as well as certain recognized built-in losses and other carryforwards, after an "ownership change" occurs. A Section 382 "ownership change" occurs if one or more stockholders or groups of stockholders who own at least 5% of our stock increase their ownership by more than 50 percentage points compared to their lowest ownership percentage during the prior three-year period (calculated on a rolling basis). The issuance of common stock (including as part of a tax-free reorganization described in Section 368 of the Code) or sales of our stock could result in (or could have resulted in) an "ownership change" under Section 382 of the Code. If an "ownership change" occurs, Section 382 of the Code would impose an annual limitation on the amount of pre-ownership change net operating losses and other losses we could use to reduce our post-ownership change taxable income, generally equal to the product of the total value of our outstanding equity immediately prior to the "ownership change" and the applicable federal long-term tax-exempt interest rate for the month of the "ownership change" (subject to certain adjustments). The applicable rate for "ownership changes" occurring in the month of December 2018 was 2.51%.

Because U.S. federal net operating losses incurred before 2018 generally may be carried forward for up to 20 years, the annual limitation may effectively provide a cap on the cumulative amount of pre-ownership change losses, including certain recognized built-in losses that may be utilized. Any pre-ownership change losses in excess of the annual limitation may be lost. In addition, if an "ownership change" were to occur, it is possible that the annual limitation imposed on our ability to use pre-ownership change losses and certain recognized built-in losses could cause a net increase in our U.S. federal income tax liability and require U.S. federal income taxes to be paid earlier than otherwise would be paid if such annual limitations were not in effect.

## Risks Related to Our Common Stock

***The price of our common stock has historically been volatile, and this volatility may affect the price at which you could sell your common stock.***

Our common stock began trading on the New York Stock Exchange ("NYSE") on June 20, 2014 and since such date the market price of our common stock has ranged (after adjusting such market prices retroactively to reflect the 15-to-1 reverse stock split effected February 28, 2019) from a low of $9.75 per share in February 2016 to a high of $407.70 per share in June 2014. This volatility may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could continue to fluctuate significantly for various reasons, including:

- general market conditions, including fluctuations in commodity prices;
- our operating and financial performance and drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- the public reaction to our press releases, our other public announcements and our filings with the SEC;
- strategic actions by our competitors;
- our failure to meet revenue, reserves or earnings estimates;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our common stock;
- sales of our common stock by us, certain investment funds (the "EnCap Funds") managed by EnCap Investments L.P. ("EnCap") or other stockholders, or the perception that such sales may occur;
- changes in accounting principles, policies, guidance, interpretations or standards;
- additions or departures of key management personnel;
- actions by our stockholders;
- domestic and international economic, legal and regulatory factors unrelated to our performance; and
- the realization of any risks described under this "Risk Factors" section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management's attention and resources and harm our business, operating results and financial condition.

***The EnCap Funds hold a significant amount of our common stock.***

The EnCap Funds, which are managed by EnCap, hold a significant percentage of the outstanding shares of our common stock. So long as EnCap continues to control a significant amount of our common stock, it will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. In any of these matters, the interests of EnCap may differ or conflict with the interests of our other stockholders. The existence of a significant stockholder may also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, this concentration of stock ownership may also adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a significant stockholder.

***Conflicts of interest could arise in the future between us, on the one hand, and EnCap and its affiliates, including its portfolio companies, on the other hand, concerning, among other things, acquisitions and divestitures, potential competitive business activities or business opportunities.***

EnCap is a leading provider of private equity to the independent sector of the U.S. oil and gas industry and manages investment funds that own a significant amount of our common stock. From time to time, we may acquire assets from entities affiliated with EnCap, including its portfolio companies, such as our acquisition of certain oil and gas leases, wells and other oil and gas rights and interests covering approximately 44,500 net acres located in the counties of Tioga and Potter in the Commonwealth of Pennsylvania from Travis Peak Resources, LLC ("Travis Peak"), which was completed on January 18, 2018 (such transaction, the "Flat Castle Acquisition"), divest assets to such entities or otherwise transact business with such entities. For example, EnCap has an interest in Caiman Energy II, LLC, which owns a significant interest in Blue Racer, a provider of firm gathering, processing and fractionation capacity for our operated acreage in the Rich Gas, Condensate and Rich Condensate Windows of the Utica Core Area. As a result, EnCap's interests with respect to matters arising in connection with our arrangements with Blue Racer may not align with our interests. EnCap and its affiliates may also, from time to time, acquire interests in businesses that directly or indirectly compete with our business, or are significant existing or potential customers. EnCap and its affiliates may acquire or seek to acquire assets we seek to acquire, and as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Any actual or perceived conflicts of interest with respect to the foregoing could make us susceptible to litigation, which could result in substantial costs or divert our management's attention and resources or otherwise harm our business and adversely impact the trading price of our common stock.

***The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the Sarbanes—Oxley Act of 2002 (the "Sarbanes—Oxley Act"), may strain our resources, increase our costs and distract management.***

We completed our initial public offering in June 2014. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. We also incur costs associated with our public company reporting requirements and with corporate governance requirements, including requirements under the Sarbanes-Oxley Act, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority, Inc. These rules and regulations have increased our legal and financial compliance costs and make some activities more time-consuming and costly. These rules and regulations also make it more difficult and more expensive for us to obtain director and officer liability insurance. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

***If we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.***

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our shares of common stock.

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

We may sell additional shares of common stock in subsequent public or private offerings. We may also issue additional shares of common stock or convertible securities. As of March 13, 2019, we had 35,193,719 outstanding shares of common stock. The EnCap Funds beneficially own an aggregate of 14,051,907 shares of our common stock, or approximately 39% of our total outstanding shares, of which approximately 2,977,485 shares have been registered with the SEC for resale. Upon the closing of the Flat Castle Acquisition, we entered into a registration rights agreement with Travis Peak, pursuant to which we agreed to register the resale of an additional 2,521,573 shares of our common stock issued to Travis Peak, an entity affiliated with EnCap, in the Flat Castle Acquisition. Subject to compliance with the Securities Act or exemptions therefrom, certain of our employees may sell their shares of common stock into the public market.

Subject to the satisfaction of vesting conditions and Rule 144 restrictions applicable to our affiliates, shares registered under our registration statements on Form S-8 filed on July 2, 2014 and June 2, 2017 relating to our equity incentive plan are available for resale immediately in the public market without restriction.

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

***Our second amended and restated certificate of incorporation and second amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.***

Our second amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our second amended and restated certificate of incorporation and second amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the ability of our stockholders to call special meetings;
- providing that, subject to the rights of holders of any class or series of preferred stock, any action required or permitted to be taken by our stockholders must be taken at a duly held annual or special meeting of stockholders and may not be taken by any consent in writing of such stockholders;
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our second amended and restated bylaws; and
- establishing advance notice and information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

***Our second amended and restated certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.***

Our second amended and restated certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware (or, if the Court of Chancery does not have jurisdiction, another state court or a federal court located within the State of Delaware) shall, to the fullest extent permitted by applicable law and subject to applicable jurisdictional requirements, be the sole and exclusive forum for any current or former stockholder (including any current or former beneficial owner) to bring claims, including claims in the right of the Company, (i) that are based upon a violation of a duty by a current or former director, officer, employee or stockholder in such capacity, or (ii) as to which the General Corporation Law of the State of Delaware confers jurisdiction upon the Court of Chancery. Any person or entity purchasing or otherwise acquiring any interest in shares of our common stock shall be deemed to have notice of and consented to the provisions of our second amended and restated certificate of incorporation described above. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits against us and our directors, officers and other employees. Alternatively, if a court were to find these provisions of our second amended and restated certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

***We do not intend to pay cash dividends on our common stock, and the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.***

We do not plan to declare cash dividends on shares of our common stock in the foreseeable future. Additionally, the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes place certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your common stock at a price greater than you paid for it.

***For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.***

We are classified as an "emerging growth company" under the JOBS Act. For as long as we are an emerging growth company, which may be up to 5 full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act, (2) comply with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) provide certain disclosure regarding executive compensation required of larger public companies or (4) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company for up to 5 years, following our initial public offering, although we will lose that status sooner if we have more than $1.07 billion of revenues in a fiscal year, have more than $700.0 million in market value of our common stock held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a 3-year period.

***We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.***

Our second amended and restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of our common stock.

***If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.***

The trading market for our common stock is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

## Item 1B. Unresolved Staff Comments

Not applicable.

## Item 3. Legal Proceedings

Information regarding the Company's legal proceedings is set forth in "Note 13 —Commitments and Contingencies," located in the Notes to the Consolidated Financial Statements included in Part II Item 8 of this Annual Report and is incorporated herein by reference.

## Item 4. Mine Safety Disclosures

Not applicable.

## PART II

### Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

**Common Stock**

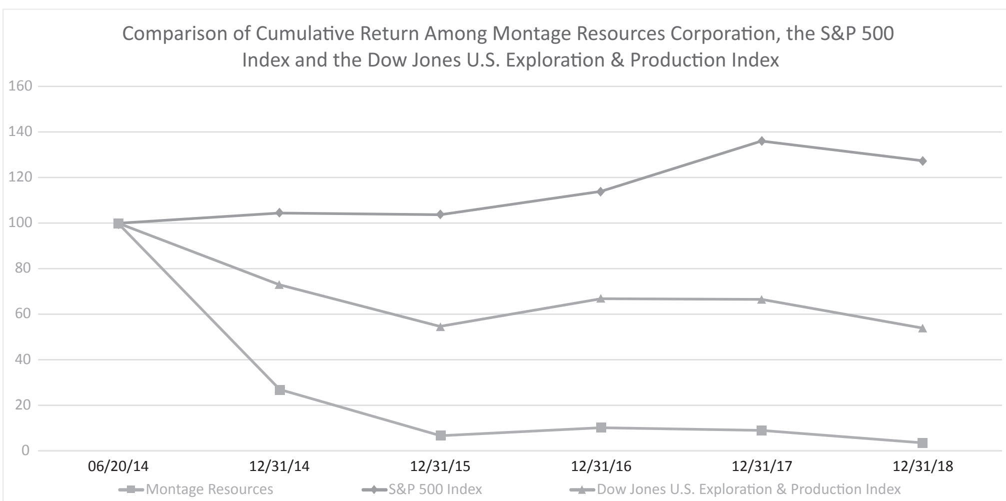
We have one class of common shares outstanding, having a par value of $0.01 per share ("Common Stock"). Our Common Stock is traded on the NYSE under the symbol "MR". As of March 10, 2019, our Common Stock was held by 11 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

**Dividend Policy**

We have not paid any cash dividends since our inception, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the growth of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon then-existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant. In addition, certain of our debt instruments place restrictions on our ability to pay cash dividends.

**Stock Performance Graph**

The graph below shows the cumulative total shareholder return assuming the investment of $100 on June 20, 2014, the first date on which our common stock was publicly traded, in each of our Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration & Production Index.




### Item 6. Selected Financial Data

The following table shows the selected historical consolidated financial data of Montage Resources Corporation and subsidiaries for the periods and as of the dates indicated. Our historical results are not necessarily indicative of future operating results. The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data."

Effective January 1, 2018, the U.S. federal corporate tax rate was reduced from 35% to 21%. Accordingly, our historical results of operations for the years ended December 31, 2014 through December 31, 2017 reflect a higher U.S. federal corporate tax rate when compared to our financial results for the year ended December 31, 2018.

The selected historical consolidated financial data as of and for the years ended December 31, 2018, 2017, 2016, 2015 and 2014 are derived from the audited consolidated financial statements of Montage Resources Corporation. Basic and diluted net income (loss) per common share for the years ended December 31, 2018, 2017, 2016, 2015 and 2014 have been adjusted retroactively to reflect the 15-to-1 reverse stock split effected February 28, 2019.

| Statement of Operations data: (in thousands) | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2015 | 2014 |
| **REVENUES** | | | | | |
| Natural gas, oil and natural gas liquids sales | $ 498,593 | $ 380,178 | $ 223,015 | $ 234,601 | $ 137,816 |
| Brokered natural gas and marketing | 16,552 | 3,481 | 12,019 | 20,720 | — |
| Total revenues | 515,145 | 383,659 | 235,034 | 255,321 | 137,816 |
| **OPERATING EXPENSES** | | | | | |
| Lease operating | 28,289 | 20,525 | 9,023 | 13,904 | 8,518 |
| Transportation, gathering and compression | 138,766 | 124,839 | 109,226 | 85,846 | 18,114 |
| Production and ad valorem taxes | 10,141 | 8,490 | 7,927 | 3,722 | 2,163 |
| Brokered natural gas and marketing expense | 16,886 | 3,191 | 12,268 | 26,173 | — |
| Depreciation, depletion and amortization | 134,277 | 118,818 | 92,948 | 244,750 | 89,218 |
| Exploration | 49,563 | 50,208 | 52,775 | 116,211 | 21,186 |
| General and administrative | 44,389 | 44,553 | 39,431 | 46,409 | 42,109 |
| Rig termination and standby | — | 1 | 3,846 | 9,672 | 3,283 |
| Impairment of proved oil and gas properties | — | — | 17,665 | 691,334 | 34,855 |
| Accretion of asset retirement obligations | 663 | 544 | 391 | 1,623 | 791 |
| (Gain) loss on sale of assets | (1,815) | (179) | 6,936 | (4,737) | (960) |
| Gain on reduction of pension liability | — | — | — | — | (2,208) |
| Total operating expenses | 421,159 | 370,990 | 352,436 | 1,234,907 | 217,069 |
| **OPERATING INCOME (LOSS)** | **93,986** | **12,669** | **(117,402)** | **(979,586)** | **(79,253)** |
| **OTHER INCOME (EXPENSE)** | | | | | |
| Gain (loss) on derivative instruments | (21,169) | 45,365 | (52,338) | 56,021 | 20,791 |
| Interest expense, net | (53,990) | (49,490) | (50,789) | (53,400) | (48,347) |
| Gain (loss) on early extinguishment of debt | — | — | 14,489 | (59,392) | — |
| Other income (expense) | (1) | (19) | (149) | 400 | 353 |
| Total other income (expense), net | (75,160) | (4,144) | (88,787) | (56,371) | (27,203) |
| **INCOME (LOSS) BEFORE INCOME TAXES** | **18,826** | **8,525** | **(206,189)** | **(1,035,957)** | **(106,456)** |
| **INCOME TAX BENEFIT (EXPENSE)** | — | — | (546) | 74,166 | (73,519) |
| **NET INCOME (LOSS)** | **$ 18,826** | **$ 8,525** | **$ (206,735)** | **$ (961,791)** | **$ (179,975)** |
| **NET INCOME (LOSS) PER COMMON SHARE** | | | | | |
| Basic | $ 0.94 | $ 0.49 | $ (12.84) | $ (66.21) | $ (18.70) |
| Diluted | $ 0.94 | $ 0.48 | $ (12.84) | $ (66.21) | $ (18.70) |
| **Statement of Cash Flow data:** | | | | | |
| Net cash provided by (used in) | | | | | |
| Operating activities | $ 225,093 | $ 112,746 | $ 6,405 | $ 80,299 | $ 8,513 |
| Investing activities | (266,250) | (292,469) | (89,318) | (437,268) | (718,436) |
| Financing activities | 29,892 | (4,282) | 99,737 | 473,857 | 667,931 |
| **Balance Sheet data:** | | | | | |
| Cash and cash equivalents | $ 5,959 | $ 17,224 | $ 201,229 | $ 184,405 | $ 67,517 |
| Total property and equipment, net | 1,296,358 | 1,114,372 | 947,500 | 993,968 | 1,722,827 |
| Total assets | 1,433,769 | 1,223,527 | 1,198,644 | 1,266,665 | 1,879,709 |
| Credit facility | 32,500 | — | — | — | — |
| Total debt | 497,778 | 495,021 | 492,278 | 527,248 | 408,754 |
| Total stockholders' equity | 687,486 | 572,354 | 556,607 | 633,374 | 1,155,912 |
| **Other financial data:** | | | | | |
| Adjusted EBITDAX | $ 261,597 | $ 189,138 | $ 102,071 | $ 120,976 | $ 67,347 |

## Non-GAAP Financial Measure

"Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense or interest income; income taxes; write-down of abandoned leases; impairments; depreciation, depletion and amortization ("DD&A"); amortization of deferred financing costs; gain (loss) on derivative instruments, net cash receipts (payments) on settled derivative instruments, and premiums (paid) received on options that settled during the period; non-cash compensation expense; gain or loss from sale of interest in gas properties; exploration expenses; and other unusual or infrequent items. Adjusted EBITDAX, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with U.S. GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with U.S. GAAP. Adjusted EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under our revolving credit facility and the indenture governing our senior unsecured notes.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from operations to Adjusted EBITDAX for the periods presented:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2015 | 2014 |
| Net income (loss) | $ 18,826 | $ 8,525 | $ (206,735) | $ (961,791) | $ (179,975) |
| Depreciation, depletion and amortization | 134,277 | 118,818 | 92,948 | 244,750 | 89,218 |
| Exploration expense | 49,563 | 50,208 | 52,775 | 116,211 | 21,186 |
| Rig termination and standby | — | 1 | 3,846 | 9,672 | 3,283 |
| Stock-based compensation | 7,891 | 9,301 | 6,216 | 4,635 | 256 |
| Impairment of proved oil and gas properties | — | — | 17,665 | 691,334 | 34,855 |
| Accretion of asset retirement obligations | 663 | 544 | 391 | 1,623 | 791 |
| (Gain) loss on sale of assets | (1,815) | (179) | 6,936 | (4,737) | (960) |
| Gain on reduction of pension obligations | — | — | — | — | (2,208) |
| (Gain) loss on derivative instruments | 21,169 | (45,365) | 52,338 | (56,021) | (20,791) |
| Net cash receipts (payments) on settled derivatives | (26,985) | (2,224) | 38,696 | 37,074 | 564 |
| Net cash paid for option premium | — | — | — | — | (385) |
| Interest expense, net | 53,990 | 49,490 | 50,789 | 53,400 | 48,347 |
| (Gain) loss on early extinguishment of debt | — | — | (14,489) | 59,392 | — |
| Merger related expenses | 4,017 | — | — | — | — |
| Other (income) expense | 1 | 19 | 149 | (400) | (353) |
| Income tax (benefit) expense | — | — | 546 | (74,166) | 73,519 |
| **Adjusted EBITDAX** | **$ 261,597** | **$ 189,138** | **$ 102,071** | **$ 120,976** | **$ 67,347** |

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

*The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in natural gas, NGLs and oil prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements." Also, see the risk factors and other cautionary statements described in "Item 1A. Risk Factors" of this Annual Report. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.*

### Overview of Our Business

We are an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin. As of December 31, 2018, we had assembled an acreage position approximating 241,000 net acres in Ohio and Pennsylvania. As of December 31, 2018, we had approximately 134,000 net acres in the Utica Shale in Ohio and Pennsylvania within the Utica Core Area, which we believe to be the most prolific part of the play, and approximately 14,500 net acres of stacked pay opportunity are located in the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as our Marcellus Area. Additionally, we own approximately 107,000 net acres (which are approximately 94% held by production) outside of the Utica Core Area that may be prospective for the oil window of the Utica Shale.

We are the operator of approximately 94% of our proved reserves within the Utica Core Area and our Marcellus Area. We intend to focus on developing our substantial inventory of horizontal drilling locations during commodity price environments that will allow us to generate attractive returns and will continue to opportunistically add to this acreage position where we can acquire acreage at attractive prices.

As of December 31, 2018:

- we were operating 2 horizontal rigs in the Utica Core Area;
- we, or our operating partners, had commenced drilling 256 gross (136.1 net) wells within the Utica Core Area and our Marcellus Area, of which 2 gross (1.9 net) were top holed, 2 gross (1.5 net) were drilling, 12 gross (6.5 net) were awaiting completion, and 240 gross (126.2 net) had been turned to sales.
- we had average daily production for the year ended December 31, 2018 of approximately 343.2 MMcfe, which was comprised of approximately 72% natural gas, 17% NGLs and 11% oil; and
- our estimated proved reserves were 1,864.7 Bcfe, or 310.8 MMBoe, based on reserve reports prepared by SIS, our independent petroleum engineers for the year ended December 31, 2018, approximately 36% of which were proved developed reserves. Our estimated proved reserves were approximately 82% natural gas, 11% NGLs and 7% oil, as of December 31, 2018.

### Factors That Significantly Affect Our Financial Condition and Results of Operations

We derive substantially all of our revenues from the production and sale of natural gas, NGLs and oil that are extracted from our natural gas during processing. During the year ended December 31, 2018, our revenues were derived approximately 53%, 17% and 27% from the production and sale of natural gas, NGLs and oil, respectively (with the remaining 3% of revenues attributable to brokered natural gas and marketing revenue). Our revenues, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Natural gas, NGLs and oil prices have historically been volatile and may fluctuate widely in the future due to a variety of factors, including, but not limited to, prevailing economic conditions, supply and demand of hydrocarbons in the marketplace and geopolitical events such as wars or natural disasters. Sustained periods of low prices for these commodities would materially and adversely affect our financial condition, our results of operations, the quantities of natural gas, NGLs and oil that we can economically produce and our ability to access capital.

We use commodity derivative instruments to manage and reduce price volatility and other market risks associated with our production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter commodity derivative contracts with large financial institutions. Please read "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional discussion of our commodity derivative contracts.

Like other businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an exploration and production company depletes part of its asset base with each unit of reserves it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production in a cost effective manner. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost effective manner and to timely obtain drilling permits and regulatory approvals.

Our financial condition and results of operations, including the growth of production, cash flows and reserves, are driven by several factors, including:

- success in drilling new wells;
- natural gas, NGLs and oil prices;
- the availability of attractive acquisition opportunities and our ability to execute them;
- the amount of capital we invest in the leasing and development of our properties;
- facility or equipment availability and unexpected downtime;
- delays imposed by or resulting from compliance with regulatory requirements; and
- the rate at which production volumes on our wells naturally decline.

**Factors That Significantly Affect Comparability of Our Financial Condition and Results of Operations**

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

*Financing Arrangements*. During 2016, the Company repurchased $39.5 million of outstanding senior unsecured notes in open market purchases for $23.4 million. The principal of the outstanding senior unsecured notes that were repurchased less cash proceeds and unamortized debt discount and deferred financing costs were charged to gain on early extinguishment of debt, totaling $14.5 million for the fiscal year. The Company repurchased all such senior unsecured notes with cash on hand.

*Drilling Joint Venture*. On December 22, 2017, we entered into definitive agreements with Sequel Energy Group LLC ("Sequel") (an affiliate of GSO Capital Partners LP) to establish a drilling joint venture on our Utica Shale acreage in Guernsey and Monroe counties in southeast Ohio. We have committed funding from Sequel of up to $285 million to fund its proportionate share of two drilling programs comprising of 33 gross wells in aggregate. We will retain 50% of our pre-carry working interest in the first program and 30% of our pre-carry working interest in the second program. We will receive a 15% carried interest on drilling and completion capital expenditures incurred in each well program, which will be proportionately reduced based upon our retained pre-carry working interest in such well program, and a significant portion of Sequel's working interest in each well program will revert to Montage once a certain return is realized by Sequel in each program. We will be the operator of all wells drilled within each well program.

*Flat Castle Acquisition*. On January 18, 2018, Eclipse Resources-PA, LP, a wholly owned subsidiary of the Company, completed its acquisition of certain oil and gas leases, wells and other oil and gas rights and interests covering approximately 44,500 net acres located in the counties of Tioga and Potter in the Commonwealth of Pennsylvania from Travis Peak. The aggregate adjusted purchase price for the Flat Castle Acquisition was $92.2 million, which was paid entirely with approximately 2.5 million shares of the Company's common stock.

Please see "Items 1 and 2. Business and Properties—Recent Developments" for a description of other recent developments and transactions that may affect the comparability of our historical financial condition and results of operations for the periods presented to future periods.

**Source of Our Revenues**

Substantially all of our historical revenues are derived from the production and sale of natural gas, NGLs and oil, and do not include the effects of derivatives. Revenues from product sales are a function of the volumes produced, prevailing market prices, product quality, gas Btu content and transportation costs. We generally sell production at a specific delivery point, pay transportation costs to a third party and receive proceeds from the purchaser with no transportation deduction. We record transportation costs as transportation, gathering and compression expense. We also may derive revenue from brokered gas or revenue we receive as a result of selling natural gas that is not related to our production and from the release of firm transportation capacity, which we refer to as brokered natural gas and marketing revenue. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

**Principal Components of Our Cost Structure**

- *Lease operating.* These are day-to-day costs incurred to bring hydrocarbons out of the ground along with the daily costs incurred to maintain our producing properties. Such costs include compensation of our field employees, maintenance, repairs and workovers expenses related to our natural gas and oil properties.
- *Transportation, gathering and compression.* These are costs incurred to bring natural gas, NGLs, and oil to the market. Such costs include the costs to operate and maintain our low- and high-pressure gathering and compression systems as well as fees paid to third parties who operate gathering systems that transport our gas. They also include costs to process and extract NGLs from our produced gas and to transport our NGLs and oil to market. We often enter into fixed price long -term contracts that secure transportation and processing capacity which may include minimum volume commitments, the cost for which is included in these expenses to the extent that they are not excess capacity.
- *Production and ad valorem taxes.* Production taxes are paid on produced natural gas and oil based on a percentage of market prices or at fixed rates established by the applicable federal, state or local taxing authorities. Ad valorem taxes are generally based on reserve values at the end of each year.
- *Brokered natural gas and marketing.* These expenses are gas purchases for brokered natural gas that we buy and sell that is not related to our production and firm transportation capacity that is marketed to third parties.
- *Depreciation, depletion and amortization.* This includes the expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense.
- *Exploration.* These are geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. This category also includes unproved property impairment and expenses associated with lease expirations.
- *General and administrative.* These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance. Included in this category are any overhead expense reimbursements we receive from working interest owners of properties, for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life.

- *Impairment of oil and gas properties.* Properties are evaluated for impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. When the carrying value exceeds the sum of the future undiscounted cash flows, an impairment loss is recognized for the difference between the fair market value and carrying value of the asset.
- *Accretion expense.* This expense includes the monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines and other facilities.
- *Gain (loss) on derivative instruments.* We utilize commodity derivative contracts to reduce our exposure to fluctuations in the price of gas. None of our derivative contracts are designated as hedges for accounting purposes. Consequently, our derivative contracts are marked-to-market each quarter with changes in fair value recognized currently as a gain or loss in our results of operations. The amount of future gain or loss recognized on derivative instruments is dependent upon future gas prices, which will affect the value of the contracts. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. In addition to gains and losses recognized from changes in fair value of the derivative instruments, gain (loss) on derivative instruments includes actual amounts realized from settlement of derivative instruments upon expiration.
- *Interest expense.* We have historically financed a portion of our cash requirements with proceeds from fixed-rate senior unsecured notes and our revolving credit facility. As a result, we incur interest expense that is affected by our financing decisions. We capitalize interest on expenditures for significant exploration and development projects while activities are in progress to bring the assets to their intended use. Upon completion of construction of the asset, the associated capitalized interest costs are included within our asset base and depleted accordingly.

**How We Evaluate Our Operations**

In evaluating our current and future financial results, we focus on production and revenue growth, lease operating expense, general and administrative expense (both before and after non-cash stock compensation expense) and operating margin per unit of production. In addition to these metrics, we use Adjusted EBITDAX, a non-GAAP measure, to evaluate our financial results. We define Adjusted EBITDAX as net income (loss) before interest expense or interest income; income taxes; write-down of abandoned leases; impairments; DD&A; amortization of deferred financing costs; gain (loss) on derivative instruments, net cash receipts (payments) on settled derivative instruments, and premiums (paid) received on options that settled during the period; non-cash compensation expense; gain or loss from sale of interest in gas properties; exploration expenses; and other unusual or infrequent items. Adjusted EBITDAX is not a measure of net income as determined by generally accepted accounting principles in United States, or "U.S. GAAP."

In addition to the operating metrics above, as we grow our reserve base, we will assess our capital spending by calculating our operated proved developed reserves and our operated proved developed finding costs and development costs. We believe that operated proved developed finding and development costs are one of the key measurements of the performance of an oil and gas exploration and production company. We will focus on our operated properties as we control the location, spending and operations associated with drilling these properties. In determining our proved developed finding and development costs, only cash costs incurred in connection with exploration and development will be used in the calculation, while the costs of acquisitions will be excluded because our board approves each material acquisition. In evaluating our proved developed reserve additions, any reserve revisions for changes in commodity prices between years will be excluded from the assessment, but any performance related reserve revisions are included.

We also continually evaluate our rates of return on invested capital in our wells. These rates of return calculations may include corporate level items such as land costs, general and administrative expenses, midstream costs and cash settled derivatives. We believe the quality of our assets combined with our technical and managerial expertise can generate attractive rates of return as we develop our acreage in the Utica Core Area and our Marcellus Area. We review changes in drilling and completion costs, lease operating costs, natural gas, NGLs and oil prices, well productivity, and other factors in order to focus our drilling on the highest rate of return areas within our acreage on a per well basis.

## Overview of the Year Ended December 31, 2018 Results

Operationally, our performance during the year ended December 31, 2018 reflects continued development of our acreage, while focusing on capital preservation in the current commodity price environment. During the year ended December 31, 2018, we achieved the following financial and operating results:

- increased our average daily net production for the year ended December 31, 2018 by 10% over the prior year, to 343.2 MMcfe per day;
- commenced drilling 26 gross (13.1 net) operated Utica Shale wells, commenced completions of 31 gross (16.9 net) operated Utica Shale wells and turned-to-sales 30 gross (17.6 net) operated Utica and Marcellus Shale wells during the year ended December 31, 2018;
- recognized net income of $18.8 million for the year ended December 31, 2018 compared to net income of $8.5 million for the year ended December 31, 2017; and
- realized Adjusted EBITDAX of $261.6 million for the year ended December 31, 2018 compared to $189.1 million for the year ended December 31, 2017. Adjusted EBITDAX is a non-GAAP financial measure. See "Item 6. Selected Financial Data—Non-GAAP Financial Measure" for more information.

## Market Conditions

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. The following table lists average daily, high, low and average monthly settled NYMEX Henry Hub prices for natural gas and average daily, high and low NYMEX WTI prices for oil for the years ended December 31, 2018, 2017, and 2016:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| NYMEX Henry Hub High ($/MMBtu) | $ 6.24 | $ 3.71 | $ 3.80 |
| NYMEX Henry Hub Low ($/MMBtu) | 2.49 | 2.44 | 1.49 |
| Average Daily NYMEX Henry Hub ($/MMBtu) | 3.15 | 2.99 | 2.52 |
| Average Monthly Settled NYMEX Henry Hub ($/MMBtu) | 3.09 | 3.11 | 2.46 |
| NYMEX WTI High ($/Bbl) | $ 77.41 | $ 60.46 | $ 54.01 |
| NYMEX WTI Low ($/Bbl) | 44.48 | 42.48 | 26.19 |
| Average Daily NYMEX WTI ($/Bbl) | 65.23 | 50.80 | 43.29 |

Historically, commodity prices have been extremely volatile, and we expect this volatility to continue for the foreseeable future. A decline in commodity prices could materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. We make price assumptions that are used for planning purposes, and a significant portion of our cash outlays, including rent, salaries and noncancelable capital commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, our financial results are likely to be adversely and disproportionately affected because these cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

The Company is committed to profitably developing its natural gas, NGLs and condensate reserves through an environmentally responsible and cost-effective operational plan. The Company's revenues, earnings, liquidity and ability to grow are substantially dependent on the prices it receives for, and the Company's ability to develop its reserves. Despite the continued low price commodity environment, the Company believes the long-term outlook for its business is favorable due to the Company's resource base, low cost structure, risk management strategies, and disciplined investment of capital.

It is difficult to quantify the impact of changes in future commodity prices on our reported estimated net proved reserves with any degree of certainty because of the various components and assumptions used in the process. However, the below sensitivity analysis demonstrates the potential impact of a 10% increase and decrease in commodity pricing to our reserves and Standardized Measure assuming all other inputs remain constant.

| | Oil | Natural Gas | Estimated Proved Reserves (Bcfe) | Standardized Measure of Discounted Future Net Cash Flows (PV-10) |
|---|---|---|---|---|
| **Commodity Pricing - SEC** | $ 65.56 | $ 3.10 | 1,864.7 | $ 1,366.7 |
| **Reserves Sensitivity:** | | | | |
| 10% Increase | $ 72.12 | $ 3.41 | 1,882.6 | $ 1,628.3 |
| 10% Decrease | $ 59.00 | $ 2.79 | 1,791.2 | $ 1,004.0 |

We consider future commodity prices when determining our development plan, but many other factors are also considered. To the extent there is a significant increase or decrease in commodity prices in the future, we will assess the impact on our development plan at that time, and we may respond to such changes by altering our capital budget or our development plan. We plan to fund our development budget with a portion of the cash on hand at December 31, 2018, cash flows from operations, borrowings under our revolving credit facility, and proceeds from asset sales.

**Results of Operations**

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

**Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations**

The following table illustrates the revenue attributable to our operations for the years ended December 31, 2018 and 2017:

| | Year Ended December 31, 2018 | Year Ended December 31, 2017 | Change |
|---|---|---|---|
| **Revenues (in thousands)** | | | |
| Natural gas sales | $ 274,239 | $ 241,379 | $ 32,860 |
| NGL sales | 86,152 | 64,109 | 22,043 |
| Oil sales | 138,202 | 74,690 | 63,512 |
| Brokered natural gas and marketing revenue | 16,552 | 3,481 | 13,071 |
| Total revenues | $ 515,145 | $ 383,659 | $ 131,486 |

Our production grew by approximately 11.8 Bcfe for the year ended December 31, 2018 over the year ended December 31, 2017, as we placed new wells into production, partially offset by natural declines in well production. Our production for the years ended December 31, 2018 and 2017 is set forth in the following table:

| | Year Ended December 31, 2018 | Year Ended December 31, 2017 | Change |
|---|---|---|---|
| **Production:** | | | |
| Natural gas (MMcf) | 89,965.7 | 87,404.2 | 2,561.5 |
| NGLs (Mbbls) | 3,503.1 | 2,713.7 | 789.4 |
| Oil (Mbbls) | 2,378.0 | 1,622.4 | 755.6 |
| Total (MMcfe) | 125,252.3 | 113,420.8 | 11,831.5 |
| | | | |
| **Average daily production volume:** | | | |
| Natural gas (Mcf/d) | 246,481 | 239,464 | 7,017 |
| NGLs (Bbls/d) | 9,598 | 7,435 | 2,163 |
| Oil (Bbls/d) | 6,515 | 4,445 | 2,070 |
| Total (Mcfe/d) | 343,159 | 310,744 | 32,415 |

Our average realized price (including cash derivative settlements and firm third-party transportation costs) received during the year ended December 31, 2018 was $3.37 per Mcfe compared to $2.99 per Mcfe during the year ended December 31, 2017. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices of production volumes should include the total impact of firm transportation expense. Our average realized price (including all derivative settlements and third-party firm transportation costs) calculation also includes all cash settlements for derivatives. Average sales price (excluding cash settled derivatives) does not include derivative settlements or third party transportation costs, which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of operations. Average sales price (excluding cash settled derivatives) does include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the years ended December 31, 2018 and 2017 are shown below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | Change |
| **Average realized price (excluding cash settled derivatives and firm transportation)** | | | |
| Natural gas ($/Mcf) | $ 3.05 | $ 2.76 | $ 0.29 |
| NGLs ($/Bbl) | 24.59 | 23.62 | 0.97 |
| Oil ($/Bbl) | 58.12 | 46.04 | 12.08 |
| Total average prices ($/Mcfe) | 3.98 | 3.35 | 0.63 |
| **Average realized price (including cash settled derivatives, excluding firm transportation)** | | | |
| Natural gas ($/Mcf) | $ 2.96 | $ 2.79 | $ 0.17 |
| NGLs ($/Bbl) | 24.32 | 21.96 | 2.36 |
| Oil ($/Bbl) | 50.47 | 46.14 | 4.33 |
| Total average prices ($/Mcfe) | 3.77 | 3.33 | 0.44 |
| **Average realized price (including firm transportation, excluding cash settled derivatives)** | | | |
| Natural gas ($/Mcf) | $ 2.50 | $ 2.31 | $ 0.19 |
| NGLs ($/Bbl) | 24.59 | 23.62 | 0.97 |
| Oil ($/Bbl) | 58.12 | 46.04 | 12.08 |
| Total average prices ($/Mcfe) | 3.59 | 3.01 | 0.58 |
| **Average realized price (including cash settled derivatives and firm transportation)** | | | |
| Natural gas ($/Mcf) | $ 2.41 | $ 2.34 | $ 0.07 |
| NGLs ($/Bbl) | 24.32 | 21.96 | 2.36 |
| Oil ($/Bbl) | 50.47 | 46.14 | 4.33 |
| Total average prices ($/Mcfe) | 3.37 | 2.99 | 0.38 |

**Brokered natural gas and marketing revenue** was $16.6 million in the year ended December 31, 2018 compared to $3.5 million in the year ended December 31, 2017. Brokered natural gas and marketing revenue includes revenue we receive as a result of selling natural gas that is not related to our production and from the release of firm transportation capacity. The increase from the year ended December 31, 2017 to the year ended December 31, 2018 is due to an increase in the amount of firm transportation that was available for brokered gas transactions or release to third parties during the year ended December 31, 2018.

## Costs and Expenses

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per Mcfe, basis. The following table presents information about certain of our expenses for the years ended December 31, 2018 and 2017:

| | Year Ended December 31, 2018 | Year Ended December 31, 2017 | Change |
|---|---|---|---|
| **Operating expenses (in thousands)** | | | |
| Lease operating | $ 28,289 | $ 20,525 | $ 7,764 |
| Transportation, gathering and compression | 138,766 | 124,839 | 13,927 |
| Production and ad valorem taxes | 10,141 | 8,490 | 1,651 |
| Depreciation, depletion and amortization | 134,277 | 118,818 | 15,459 |
| General and administrative | 44,389 | 44,553 | (164) |
| **Operating expenses per Mcfe:** | | | |
| Lease operating | $ 0.23 | $ 0.18 | $ 0.05 |
| Transportation, gathering and compression | 1.10 | 1.10 | — |
| Production and ad valorem taxes | 0.08 | 0.07 | 0.01 |
| Depreciation, depletion and amortization | 1.07 | 1.05 | 0.02 |
| General and administrative | 0.35 | 0.39 | (0.04) |

**Lease operating** expense was $28.3 million in the year ended December 31, 2018 compared to $20.5 million in the year ended December 31, 2017. Lease operating expense per Mcfe was $0.23 in the year ended December 31, 2018 compared to $0.18 in the year ended December 31, 2017. The increase of $7.8 million and $0.05 per Mcfe is attributable to increases in producing wells and salt water disposal expenses during the year ended December 31, 2018. Lease operating expenses include normally recurring expenses to operate our wells and non-recurring workovers and repairs.

**Transportation, gathering and compression** expense was $138.8 million in the year ended December 31, 2018 compared to $124.8 million in the year ended December 31, 2017. Transportation, gathering and compression expense per Mcfe was $1.10 in each of the years ended December 31, 2018 and 2017. The following table details our transportation, gathering and compression expenses for the years ended December 31, 2018 and 2017:

| | Year Ended December 31, 2018 | Year Ended December 31, 2017 | Change |
|---|---|---|---|
| **Transportation, gathering and compression (in thousands):** | | | |
| Gathering, compression and fuel | $ 42,461 | $ 46,466 | $ (4,005) |
| Processing and fractionation | 39,132 | 32,468 | 6,664 |
| Liquids transportation and stabilization | 7,986 | 6,746 | 1,240 |
| Marketing | 19 | 27 | (8) |
| Firm transportation | 49,168 | 39,132 | 10,036 |
| | $138,766 | $124,839 | $13,927 |
| **Transportation, gathering and compression per Mcfe:** | | | |
| Gathering, compression and fuel | $ 0.34 | $ 0.41 | $ (0.07) |
| Processing and fractionation | 0.31 | 0.29 | 0.02 |
| Liquids transportation and stabilization | 0.06 | 0.06 | — |
| Marketing | — | — | — |
| Firm transportation | 0.39 | 0.34 | 0.05 |
| | $ 1.10 | $ 1.10 | $ — |

The increase of $13.9 million in the year ended December 31, 2018 was due to our production growth and increased firm transportation expenses, which increased primarily due to additional capacity that came online during the second half of 2018. These expenses were consistent on a per unit basis as increased firm transportation and production costs were offset by lower contractual gathering rates.

**Production and ad valorem taxes** are paid based on market prices and applicable tax rates. Production and ad valorem taxes were $10.1 million in the year ended December 31, 2018 compared to $8.5 million in the year ended December 31, 2017. Production and ad valorem taxes per Mcfe was $0.08 in the year ended December 31, 2018 compared to $0.07 in the year ended December 31, 2017. The $1.6 million increase in aggregate production and ad valorem taxes is primarily due to increased production and well count. The increase of $0.01 on a per unit basis is driven by increased severance taxes associated with our increased liquids production.

**Depreciation, depletion and amortization** was approximately $134.3 million in the year ended December 31, 2018 compared to $118.8 million in the year ended December 31, 2017. This $15.5 million increase is primarily due to an increase in production and proved property costs. On a per Mcfe basis, DD&A increased to $1.07 in the year ended December 31, 2018 from $1.05 in the year ended December 31, 2017, which was primarily due to a higher depletion rate resulting from our reserves increasing at a lower rate than our capital cost.

**General and administrative** expense was $44.4 million for the year ended December 31, 2018 compared to $44.6 million for the year ended December 31, 2017. General and administrative expense per Mcfe was $0.35 in the year ended December 31, 2018 compared to $0.39 in the year ended December 31, 2017. The $0.2 million decrease was primarily due to lower salaries and benefits associated with decreased head count, and lower professional fees partially offset by approximately $4.0 million of expense related to the BRMR Merger. The decrease of $0.04 per Mcfe was primarily due to fixed costs spread across increased levels of production as of December 31, 2018 compared to December 31, 2017. General and administrative expense includes $7.9 million and $9.3 million of stock-based compensation expense for the years ended December 31, 2018 and 2017, respectively.

### Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include brokered natural gas and marketing expense, exploration, rig termination and standby, accretion of asset retirement obligations, impairment of proved oil and natural gas properties and (gain) loss on sale of assets. The following table details our other operating expenses for the years ended December 31, 2018 and 2017:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | Change |
| **Other operating expenses (in thousands):** | | | |
| Brokered natural gas and marketing expense | $ 16,886 | $ 3,191 | $ 13,695 |
| Exploration | 49,563 | 50,208 | (645) |
| Rig termination and standby | — | 1 | (1) |
| Accretion of asset retirement obligations | 663 | 544 | 119 |
| (Gain) loss on sale of assets | (1,815) | (179) | (1,636) |

**Brokered natural gas and marketing** expense was $16.9 million for the year ended December 31, 2018 compared to $3.2 million in the year ended December 31, 2017. Brokered natural gas and marketing expense relate to gas purchases for brokered natural gas that we buy and sell that is not related to our production and firm transportation capacity that is marketed to third parties. The increase is primarily due to an increase in the amount of firm transportation that was available for brokered gas transactions or release to third parties during the year ended December 31, 2018.

**Exploration** expense decreased to $49.6 million in the year ended December 31, 2018 compared to $50.2 million in the year ended December 31, 2017. The following table details our exploration-related expenses for the years ended December 31, 2018 and 2017:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | Change |
| **Exploration expenses (in thousands):** | | | |
| Geological and geophysical | $ 1,510 | $ 1,098 | $ 412 |
| Delay rentals | 19,729 | 17,693 | 2,036 |
| Impairment of unproved properties | 27,608 | 28,291 | (683) |
| Dry hole and other | 716 | 3,126 | (2,410) |
| | $ 49,563 | $ 50,208 | $ (645) |

**Delay rentals** were $19.7 million in the year ended December 31, 2018 compared to $17.7 million in the year ended December 31, 2017. The increase in delay rentals relates to converting lump-sum extension payments into annual delay rentals.

**Impairment of unproved properties** was $27.6 million in the year ended December 31, 2018 compared to $28.3 million in the year ended December 31, 2017. The decrease in impairment charges during the year ended December 31, 2018 was the result of a decrease in expected lease expirations due to the increase in our planned future drilling activity. As we continue to review our acreage positions and high grade our drilling inventory based on the current commodity price environment, additional leasehold impairments and abandonments may be recorded.

**Rig termination and standby** expense was less than $0.1 million in the year ended December 31, 2017. There was no rig termination and standby expense in the year ended December 31, 2018.

**Accretion of asset retirement obligations** was $0.7 million in the year ended December 31, 2018, compared to $0.5 million in the year ended December 31, 2017. The increase in accretion expense primarily relates to the increase in our number of producing wells.

**(Gain) loss on sale of assets** was ($1.8) million in the year ended December 31, 2018 and ($0.2) million in the year ended December 31, 2017, each due to the sale of certain non-core assets.

### Other Income (Expense)

**Gain (loss) on derivative instruments** was ($21.2) million for the year ended December 31, 2018 compared to $45.4 million for the year ended December 31, 2017, primarily due to changes in commodity prices during each year. Cash payments were approximately $27.0 million and $2.2 million for the derivative instruments that settled during the years ended December 31, 2018 and 2017, respectively.

**Interest expense, net** was $54.0 million for the year ended December 31, 2018 compared to $49.5 million for year ended December 31, 2017. The increase in interest expense was primarily due to our increased borrowings under our credit facility during the year ended December 31, 2018.

**Income tax benefit (expense)** was not recognized for the years ended December 31, 2018 and 2017 due to the Company recording a higher valuation allowance related to its pre-tax losses and reducing the valuation allowance to the extent of pre-tax income.

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

**Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations**

The following table illustrates the revenue attributable to our operations for the years ended December 31, 2017 and 2016:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **Change** |
| **Revenues (in thousands):** | | | |
| Natural gas sales | $ 241,379 | $ 134,618 | $ 106,761 |
| NGLs sales | 64,109 | 38,204 | 25,905 |
| Oil sales | 74,690 | 50,193 | 24,497 |
| Brokered natural gas and marketing revenue | 3,481 | 12,019 | (8,538) |
| Total revenues | $ 383,659 | $ 235,034 | $ 148,625 |

Our production grew by approximately 29.8 Bcfe for the year ended December 31, 2017 over the year ended December 31, 2016, as we placed new wells into production, partially offset by natural declines in well production. Our production for the years ended December 31, 2017 and 2016 is set forth in the following table:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **Change** |
| **Production:** | | | |
| Natural gas (MMcf) | 87,404.2 | 60,921.9 | 26,482.3 |
| NGLs (Mbbls) | 2,713.7 | 2,446.2 | 267.5 |
| Oil (Mbbls) | 1,622.4 | 1,343.8 | 278.6 |
| Total (MMcfe) | 113,420.8 | 83,661.9 | 29,758.9 |
| **Average daily production volume:** | | | |
| Natural gas (Mcf/d) | 239,464 | 166,453 | 73,011 |
| NGLs (Bbls/d) | 7,435 | 6,684 | 751 |
| Oil (Bbls/d) | 4,445 | 3,672 | 773 |
| Total (Mcfe/d) | 310,744 | 228,589 | 82,155 |

Our average realized price (including cash derivative settlements and firm third-party transportation costs) received during the year ended December 31, 2017 was $2.99 per Mcfe compared to $2.76 per Mcfe during the year ended December 31, 2016. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices of production volumes should include the total impact of firm transportation expense. Our average realized price (including all derivative settlements and third-party firm transportation costs) calculation also includes all cash settlements for derivatives. Average sales price (excluding cash settled derivatives) does not include derivative settlements or third party transportation costs, which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of operations. Average sales price (excluding cash settled derivatives) does include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the years ended December 31, 2017 and 2016 are shown below:

| | Year Ended December 31, 2017 | Year Ended December 31, 2016 | Change |
|---|---|---|---|
| **Average realized price (excluding cash settled derivatives and firm transportation)** | | | |
| Natural gas ($/Mcf) | $ 2.76 | $ 2.21 | $ 0.55 |
| NGLs ($/Bbl) | 23.62 | 15.62 | 8.00 |
| Oil ($/Bbl) | 46.04 | 37.35 | 8.69 |
| Total average prices ($/Mcfe) | 3.35 | 2.67 | 0.68 |
| **Average realized price (including cash settled derivatives, excluding firm transportation)** | | | |
| Natural gas ($/Mcf) | $ 2.79 | $ 2.69 | $ 0.10 |
| NGLs ($/Bbl) | 21.96 | 15.55 | 6.41 |
| Oil ($/Bbl) | 46.14 | 44.66 | 1.48 |
| Total average prices ($/Mcfe) | 3.33 | 3.13 | 0.20 |
| **Average realized price (including firm transportation, excluding cash settled derivatives)** | | | |
| Natural gas ($/Mcf) | $ 2.31 | $ 1.71 | $ 0.60 |
| NGLs ($/Bbl) | 23.62 | 15.62 | 8.00 |
| Oil ($/Bbl) | 46.04 | 37.35 | 8.69 |
| Total average prices ($/Mcfe) | 3.01 | 2.30 | 0.71 |
| **Average realized price (including cash settled derivatives and firm transportation)** | | | |
| Natural gas ($/Mcf) | $ 2.34 | $ 2.19 | $ 0.15 |
| NGLs ($/Bbl) | 21.96 | 15.55 | 6.41 |
| Oil ($/Bbl) | 46.14 | 44.66 | 1.48 |
| Total average prices ($/Mcfe) | 2.99 | 2.76 | 0.23 |

**Brokered natural gas and marketing revenue** was $3.5 million in the year ended December 31, 2017 compared to $12.0 million in the year ended December 31, 2016. Brokered natural gas and marketing revenue includes revenue we receive as a result of selling natural gas that is not related to our production and from the release of firm transportation capacity. The decrease from the year ended December 31, 2016 to the year ended December 31, 2017 is due to increased utilization of our firm transportation capacity for operated production during the year ended December 31, 2017, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

## Costs and Expenses

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per Mcfe, basis. The following table presents information about certain of our expenses for the years ended December 31, 2017 and 2016:

| | Year Ended December 31, 2017 | Year Ended December 31, 2016 | Change |
|---|---|---|---|
| **Operating expenses (in thousands):** | | | |
| Lease operating | $ 20,525 | $ 9,023 | $ 11,502 |
| Transportation, gathering and compression | 124,839 | 109,226 | 15,613 |
| Production and ad valorem taxes | 8,490 | 7,927 | 563 |
| Depreciation, depletion and amortization | 118,818 | 92,948 | 25,870 |
| General and administrative | 44,553 | 39,431 | 5,122 |
| **Operating expenses per Mcfe:** | | | |
| Lease operating | $ 0.18 | $ 0.11 | $ 0.07 |
| Transportation, gathering and compression | 1.10 | 1.30 | (0.20) |
| Production and ad valorem taxes | 0.07 | 0.09 | (0.02) |
| Depreciation, depletion and amortization | 1.05 | 1.11 | (0.06) |
| General and administrative | 0.39 | 0.47 | (0.08) |

**Lease operating** expense was $20.5 million in the year ended December 31, 2017 compared to $9.0 million in the year ended December 31, 2016. Lease operating expense per Mcfe was $0.18 in the year ended December 31, 2017 compared to $0.11 in the year ended December 31, 2016. The increase of $11.5 million and $0.07 per Mcfe is attributable to increases in producing wells, salt water disposal expenses and workover expenses during the year ended December 31, 2017. Lease operating expenses include normally recurring expenses to operate our wells and non-recurring workovers and repairs.

**Transportation, gathering and compression** expense was $124.8 million in the year ended December 31, 2017 compared to $109.2 million in the year ended December 31, 2016. Transportation, gathering and compression expense per Mcfe was $1.10 in the year ended December 31, 2017 compared to $1.30 in the year ended December 31, 2016. The following table details our transportation, gathering and compression expenses for the years ended December 31, 2017 and 2016:

| | Year Ended December 31, 2017 | Year Ended December 31, 2016 | Change |
|---|---|---|---|
| **Transportation, gathering and compression (in thousands):** | | | |
| Gathering, compression and fuel | $ 46,466 | $ 38,474 | $ 7,992 |
| Processing and fractionation | 32,468 | 32,067 | 401 |
| Liquids transportation and stabilization | 6,746 | 8,225 | (1,479) |
| Marketing | 27 | 54 | (27) |
| Firm transportation | 39,132 | 30,406 | 8,726 |
| | $ 124,839 | $ 109,226 | $ 15,613 |
| **Transportation, gathering and compression per Mcfe:** | | | |
| Gathering, compression and fuel | $ 0.41 | $ 0.46 | $ (0.05) |
| Processing and fractionation | 0.29 | 0.38 | (0.09) |
| Liquids transportation and stabilization | 0.06 | 0.10 | (0.04) |
| Marketing | — | — | — |
| Firm transportation | 0.34 | 0.36 | (0.02) |
| | $ 1.10 | $ 1.30 | $ (0.20) |

The increase of $15.6 million in the year ended December 31, 2017 was due to our production growth and increased firm transportation expenses, which increased primarily due to additional capacity that came online during the fourth quarter of 2016. The decrease of $0.20 on a per unit basis was primarily due to increased production associated with natural gas and lower contractual rates.

**Production and ad valorem taxes** are paid based on market prices and applicable tax rates. Production and ad valorem taxes were $8.5 million in the year ended December 31, 2017 compared to $7.9 million in the year ended December 31, 2016. Production and ad valorem taxes per Mcfe was $0.07 in the year ended December 31, 2017 compared to $0.09 in the year ended December 31, 2016. The increase in aggregate production and ad valorem taxes is primarily due to increased well count. The decrease in production and ad valorem taxes on a per unit basis is due to the lower taxable value rate for the year ended December 31, 2017.

**Depreciation, depletion and amortization** was approximately $118.8 million for the year ended December 31, 2017 compared to $92.9 million in the year ended December 31, 2016. The increase is primarily due to an increase in production and proved costs. On a per Mcfe basis, DD&A decreased to $1.05 in the year ended December 31, 2017 from $1.11 in the year ended December 31, 2016, which was primarily due to a lower depletion rate resulting from increased reserves.

**General and administrative** expense was $44.6 million for the year ended December 31, 2017 compared to $39.4 million for the year ended December 31, 2016. General and administrative expense per Mcfe was $0.39 in the year ended December 31, 2017 compared to $0.47 in the year ended December 31, 2016. The aggregate increase of $5.1 million was primarily due to higher salaries and benefits associated with increased head count and the decrease of $0.08 per Mcfe was primarily due to fixed costs spread across increased levels of production, in each case, as of December 31, 2017 compared to December 31, 2016. General and administrative expense includes $9.3 million and $6.2 million of stock-based compensation expense for the years ended December 31, 2017 and 2016, respectively.

### Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include brokered natural gas and marketing expense, exploration, rig termination and standby, accretion of asset retirement obligations, impairment of proved oil and natural gas properties and (gain) loss on sale of assets. The following table details our other operating expenses for the years ended December 31, 2017 and 2016:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | Change |
| **Other operating expenses (in thousands):** | | | |
| Brokered natural gas and marketing expense | $ 3,191 | $ 12,268 | $ (9,077) |
| Exploration | 50,208 | 52,775 | (2,567) |
| Rig termination and standby | 1 | 3,846 | (3,845) |
| Accretion of asset retirement obligations | 544 | 391 | 153 |
| Impairment of proved oil and natural gas properties | — | 17,665 | (17,665) |
| (Gain) loss on sale of assets | (179) | 6,936 | (7,115) |

**Brokered natural gas and marketing** expense was $3.2 million in the year ended December 31, 2017 compared to $12.3 million in the year ended December 31, 2016. Brokered natural gas and marketing expense relate to gas purchases for brokered natural gas that we buy and sell that is not related to our production and firm transportation capacity that is marketed to third parties. The decrease is primarily due to increased utilization of our firm transportation capacity for operated production during the year ended December 31, 2017, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

**Exploration** expense decreased to $50.2 million in the year ended December 31, 2017 compared to $52.8 million in the year ended December 31, 2016. The following table details our exploration-related expenses for the years ended December 31, 2017 and 2016:

| | Year Ended December 31, 2017 | Year Ended December 31, 2016 | Change |
|---|---|---|---|
| **Exploration expenses (in thousands):** | | | |
| Geological and geophysical | $ 1,098 | $ 935 | $ 163 |
| Delay rentals | 17,693 | 20,987 | (3,294) |
| Impairment of unproved properties | 28,291 | 29,824 | (1,533) |
| Dry hole and other | 3,126 | 1,029 | 2,097 |
| | $ 50,208 | $ 52,775 | $ (2,567) |

**Delay rentals** were $17.7 million for the year ended December 31, 2017 compared to $21.0 million for the year ended December 31, 2016. The decrease in delay rentals relates to the reduction of converting future lump-sum extension payments into annual delay rentals and increased drilling activity during 2017.

**Impairment of unproved properties** was $28.3 million for the year ended December 31, 2017 compared to $29.8 million for the year ended December 31, 2016. The decrease in impairment charges during the year ended December 31, 2017 was the result of a decrease in expected lease expirations due to the increase in our planned future drilling activity. As we continue to review our acreage positions and high grade our drilling inventory based on the current commodity price environment, additional leasehold impairments and abandonments may be recorded.

**Rig termination and standby** expense was less than $0.1 million for the year ended December 31, 2017. For the year ended December 31, 2016, rig termination and standby expenses were $3.8 million related primarily to standby costs incurred from temporarily suspending our drilling operations for a portion of 2016.

**Impairment of proved oil and natural gas properties** was $17.7 million for the year ended December 31, 2016 related to certain of our Marcellus Shale properties. There was no impairment of proved oil and gas properties recognized for the year ended December 31, 2017.

**Accretion of asset retirement obligations** was $0.5 million in the year ended December 31, 2017, compared to $0.4 million in the year ended December 31, 2016. The increase in accretion expense primarily relates to the increase in our number of producing wells.

**(Gain) loss on sale of assets** was ($0.2) million for the year ended December 31, 2017 due primarily to the sale of certain non-core assets. The loss of $6.9 million for the year ended December 31, 2016 was due primarily to realizing a loss on the sale of approximately 9,900 net acres to a third party.

### Other Income (Expense)

**Gain (loss) on derivative instruments** was $45.4 million for the year ended December 31, 2017 compared to ($52.3) million for the year ended December 31, 2016, primarily due to changes in commodity prices during each year. Cash payments were approximately $2.2 million and $38.7 million for the derivative instruments that settled during the years ended December 31, 2017 and December 31, 2016, respectively.

**Interest expense, net** was $49.5 million for the year ended December 31, 2017 compared to $50.8 million for year ended December 31, 2016. The decrease in interest expense was due to the early extinguishment of debt during the year ended December 31, 2016.

**Gain (loss) on early extinguishment of debt** was $14.5 million for the year ended December 31, 2016 resulting from the repurchase of $39.5 million in aggregate principal amount of our outstanding senior unsecured notes in the open market for $23.4 million during such year. The outstanding principal amount of senior unsecured notes that we repurchased less cash proceeds and unamortized debt discount and deferred financing costs of $1.6 million were charged to gain on early extinguishment of debt. No gain or loss on early extinguishment of debt was recognized for the year ended December 31, 2017.

**Income tax benefit (expense)** was ($0.5) million for the year ended December 31, 2016 related to the write-off of certain state deferred tax assets. No income tax benefit or expense was recorded for the year ended December 31, 2017 due to reducing the valuation allowance to the extent of the tax effect of recorded pre-tax income. Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act, resulted in the Company generating a deferred tax expense of $142 million primarily due to remeasurement of our net deferred tax asset for the reduction in the U.S. statutory rate from 35% to 21%. Based on our current interpretation and subject to release of the related regulations and any future interpretative guidance, we believe the effects of the change in tax law incorporated herein are substantially complete. See Note 14— *Income Tax* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the impact of the Tax Cuts and Jobs Act on our income tax provisions for the year ended December 31, 2017. At December 31, 2017, we had approximately $546 million of NOLs for U.S. federal income tax purposes that expire at various dates from 2034 through 2037. The increase in NOLs from approximately $426 million at December 31, 2016 to $546 million at December 31, 2017 results primarily from the deduction of intangible drilling costs for U.S. federal income tax purposes. Future interpretations relating to the recently enacted U.S. federal income tax legislations, which vary from our current interpretation, may have a significant effect on our future taxable position. The impact of any such change would be recorded in the period in which such interpretations are received or legislation is enacted.

## Cash Flows, Capital Resources and Liquidity

### Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices. Our cash flows from operations also are impacted by changes in working capital. Short-term liquidity needs are satisfied by our operating cash flow, proceeds from asset sales, borrowings under our revolving credit facility, proceeds from our drilling joint venture, and proceeds from issuances of debt and equity securities. We sell a large portion of our production at the wellhead under floating market contracts.

#### *Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017*

**Net cash provided by operations** in the year ended December 31, 2018 was $225.1 million compared to $112.7 million in the year ended December 31, 2017. The increase in cash provided from operating activities reflects the increase in our production during the year-over-year comparative periods, working capital changes and the timing of cash receipts and disbursements.

**Net cash used in investing activities** in the year ended December 31, 2018 was $266.3 million compared to $292.5 million in the year ended December 31, 2017.

During the year ended December 31, 2018, we:

- spent $275.6 million on capital expenditures for oil and natural gas properties;
- spent $1.0 million on property and equipment; and
- received $10.4 million of proceeds relating to the sale of assets.

During the year ended December 31, 2017, we:

- spent $291.8 million on capital expenditures for oil and natural gas properties;
- spent $2.0 million on property and equipment; and
- received $1.3 million of proceeds relating to the sale of assets.

**Net cash provided by (used in) financing activities** in the year ended December 31, 2018 was $29.9 million compared to ($4.3) million in the year ended December 31, 2017.

During the year ended December 31, 2018, we:

- borrowed $32.5 million under our revolving credit facility; and
- withheld from employees shares totaling $1.3 million related to the settlement of equity compensation awards.

During the year ended December 31, 2017, we:

- paid $1.8 million in financing costs associated with an amendment to the credit agreement governing our revolving credit facility that, among other things, increased the borrowing base under such revolving credit facility; and
- withheld from employees shares totaling $2.0 million related to the settlement of equity compensation awards.

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

**Net cash provided by operations** in the year ended December 31, 2017 was $112.7 million compared to $6.4 million in the year ended December 31, 2016. The increase in cash provided from operating activities reflects the increase in our production and commodity prices during the year-over-year comparative periods, working capital changes and the timing of cash receipts and disbursements.

**Net cash used in investing activities** in the year ended December 31, 2017 was $292.5 million compared to $89.3 million in the year ended December 31, 2016.

During the year ended December 31, 2017, we:

- spent $291.8 million on capital expenditures for oil and natural gas properties;
- spent $2.0 million on property and equipment; and
- received $1.3 million of proceeds relating to the sale of assets.

During the year ended December 31, 2016, we:

- spent $167.4 million on capital expenditures for oil and natural gas properties;
- spent $1.2 million on property and equipment; and
- received $79.2 million of proceeds relating to the sale of assets.

**Net cash provided by (used in) financing activities** in the year ended December 31, 2017 was ($4.3) million compared to $99.7 million in the year ended December 31, 2016.

During the year ended December 31, 2017, we:

- paid $1.8 million in financing costs associated with an amendment to the credit agreement governing our revolving credit facility that, among other things, increased the borrowing base under such revolving credit facility; and

- withheld from employees shares totaling $2.0 million related to the settlement of equity compensation awards.

During the year ended December 31, 2016, we:

- purchased outstanding senior unsecured notes with aggregate principal amount of $39.5 million for $23.4 million; and
- completed a public offering of 2,500,000 shares of common stock for approximately $123.8 million of net proceeds.

**Liquidity and Capital Resources**

Our main sources of liquidity and capital resources are internally generated cash flow from operations, asset sales, borrowings under our revolving credit facility, proceeds from our drilling joint venture and access to the debt and equity capital markets. We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs, which requires substantial capital expenditures. We periodically review capital expenditures and adjust our budget based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices. We believe that our existing cash on hand, operating cash flow, proceeds from our drilling joint venture and available proceeds under our revolving credit facility will be adequate to meet our capital and operating requirements for 2019.

Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We will continue using net cash on hand, cash flows from operations, proceeds from our drilling joint venture and proceeds available under our revolving credit facility to satisfy near-term financial obligations and liquidity needs, and as necessary, we will seek additional sources of debt or equity to fund these requirements. Longer-term cash flows are subject to a number of variables including the level of production and prices we receive for our production as well as various economic conditions that have historically affected the natural gas and oil business. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales, joint venture transactions or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves

As of December 31, 2018, we were in compliance with all of our debt covenants under the credit agreement governing our revolving credit facility and the indenture governing our 8.875% senior unsecured notes due 2023. Further, based on our current forecast and activity levels, we expect to remain in compliance with all such debt covenants for the next twelve months. However, if oil and natural gas prices decrease to lower levels, we are likely to generate lower operating cash flows, which would make it more difficult for us to remain in compliance with all of our debt covenants, including requirements with respect to working capital and interest coverage ratios. This could negatively impact our ability to maintain sufficient liquidity and access to capital resources.

**Credit Arrangements**

Long-term debt at December 31, 2018 and 2017, excluding discount, totaled $543.0 million and $510.5 million, respectively. Long-term debt includes both the senior unsecured notes outstanding and, if applicable, any outstanding borrowings against our revolving credit facility.

Information related to our credit arrangements is described in Note 7— *Debt* to our consolidated financial statements and is incorporated herein by reference.

**Commodity Hedging Activities**

Our primary market risk exposure is in the prices we receive for our natural gas, NGLs and oil production. Realized pricing is primarily driven by the spot regional market prices applicable to our U.S. natural gas, NGLs and oil production. Pricing for natural gas, NGLs and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate the potential negative impact on our cash flow caused by changes in natural gas, NGLs and oil prices, we may enter into financial commodity derivative contracts to ensure that we receive minimum prices for a portion of our future natural gas production when management believes that favorable future prices can be secured. We typically hedge the NYMEX Henry Hub price for natural gas, the WTI price for oil and a NGLs basket based on prices at Mont Belvieu, Texas.

Our hedging activities are intended to support natural gas, NGLs and oil prices at targeted levels and to manage our exposure to price fluctuations. The counterparty is required to make a payment to us for the difference between the floor price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the floor price. We are required to make a payment to the counterparty for the difference between the ceiling price and the settlement price if the ceiling price is below the settlement price. These contracts may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, zero cost collars that set a floor and ceiling price for the hedged production, and puts which require us to pay a premium either up front or at settlement and allow us to receive a fixed price at our option if the put price is above the market price. As of December 31, 2018, we had entered into the following derivative contracts:

*Natural Gas Derivatives*

| Description | Volume (MMBtu/d) | Production Period | Weighted Average Price ($/MMBtu) |
|---|---|---|---|
| **Natural Gas Swaps:** | | | |
| | 30,000 | January 2019 – March 2019 | $ 2.90 |
| | 90,000 | January 2019 – December 2019 | $ 2.84 |
| **Natural Gas Collars:** | | | |
| Ceiling sold price (call) | 30,000 | October 2019 – December 2019 | $ 2.95 |
| Floor sold price (put) | 30,000 | October 2019 – December 2019 | $ 2.65 |
| **Natural Gas Three-way Collars:** | | | |
| Floor purchase price (put) | 30,000 | January 2019 – March 2019 | $ 3.00 |
| Ceiling sold price (call) | 30,000 | January 2019 – March 2019 | $ 3.40 |
| Floor sold price (put) | 30,000 | January 2019 – March 2019 | $ 2.50 |
| Floor purchase price (put) | 77,500 | January 2019 – December 2019 | $ 2.72 |
| Ceiling sold price (call) | 77,500 | January 2019 – December 2019 | $ 3.04 |
| Floor sold price (put) | 77,500 | January 2019 – December 2019 | $ 2.30 |
| Floor purchase price (put) | 50,000 | January 2020 – June 2020 | $ 2.70 |
| Ceiling sold price (call) | 50,000 | January 2020 – June 2020 | $ 2.95 |
| Floor sold price (put) | 50,000 | January 2020 – June 2020 | $ 2.25 |
| **Natural Gas Call/Put Options:** | | | |
| Call sold | 30,000 | January 2019 – March 2019 | $ 3.50 |
| Call sold | 30,000 | April 2019 – December 2019 | $ 3.00 |
| Call sold | 10,000 | January 2019 – December 2019 | $ 4.75 |
| **Basis Swaps:** | | | |
| Appalachia - Dominion | 12,500 | April 2019 – October 2019 | $ (0.52) |
| Appalachia - Dominion | 12,500 | April 2020 – October 2020 | $ (0.52) |
| Appalachia - Dominion | 20,000 | January 2020 – December 2020 | $ (0.59) |

*Oil Derivatives*

| Description | Volume (Bbls/d) | Production Period | Weighted Average Price ($/Bbl) | |
|---|---|---|---|---|
| **Oil Swaps:** | | | | |
| | 1,000 | January 2019 – March 2019 | $ | 61.00 |
| **Oil Three-way Collars:** | | | | |
| Floor purchase price (put) | 2,000 | January 2019 – December 2019 | $ | 50.00 |
| Ceiling sold price (call) | 2,000 | January 2019 – December 2019 | $ | 60.56 |
| Floor sold price (put) | 2,000 | January 2019 – December 2019 | $ | 40.00 |
| Floor purchase price (put) | 2,000 | January 2020 – June 2020 | $ | 62.50 |
| Ceiling sold price (call) | 2,000 | January 2020 – June 2020 | $ | 74.00 |
| Floor sold price (put) | 2,000 | January 2020 – June 2020 | $ | 55.00 |

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, 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. The creditworthiness of our counterparties is subject to periodic review. As of December 31, 2018, we had derivative instruments in place with Bank of Montreal, KeyBank N.A., Morgan Stanley, Capital One N.A., BP Energy Company and Goldman Sachs. We believe all of such institutions currently are an acceptable credit risk. As of December 31, 2018, we did not have any past due receivables from counterparties.

Subsequent to December 31, 2018, we entered into the following derivative instruments to mitigate our exposure to commodity prices which also includes contracts assumed as a result of the BRMR Merger:

*Natural Gas:*

| Description | Volume (MMbtu/d) | Production Period | Weighted Average Price ($/MMbtu) |
|---|---|---|---|
| **Natural Gas Swaps:** | | | |
| | 15,000 | April 2019 – September 2019 | $ 2.79 |
| **Natural Gas Collars:** | | | |
| Floor purchase price (put) | 50,000 | January 2019 – March 2019 | $ 3.00 |
| Ceiling sold price (call) | 50,000 | January 2019 – March 2019 | $ 3.52 |
| Floor purchase price (put) | 55,000 | April 2019 – June 2019 | $ 2.51 |
| Ceiling sold price (call) | 55,000 | April 2019 – June 2019 | $ 2.81 |
| Floor purchase price (put) | 75,000 | July 2019 – September 2019 | $ 2.50 |
| Ceiling sold price (call) | 75,000 | July 2019 – September 2019 | $ 2.87 |
| Floor purchase price (put) | 35,000 | October 2019 – December 2019 | $ 2.64 |
| Ceiling sold price (call) | 35,000 | October 2019 – December 2019 | $ 2.96 |
| Floor purchase price (put) | 30,000 | January 2020 – March 2020 | $ 2.72 |
| Ceiling sold price (call) | 30,000 | January 2020 – March 2020 | $ 3.15 |
| Floor purchase price (put) | 15,000 | April 2020 – June 2020 | $ 2.50 |
| Ceiling sold price (call) | 15,000 | April 2020 – June 2020 | $ 2.80 |
| **Natural Gas Three-way Collars:** | | | |
| Floor purchase price (put) | 49,000 | January 2019 – March 2019 | $ 3.15 |
| Ceiling sold price (call) | 49,000 | January 2019 – March 2019 | $ 3.56 |
| Floor sold price (put) | 49,000 | January 2019 – March 2019 | $ 2.63 |
| Floor purchase price (put) | 40,000 | April 2019 – June 2019 | $ 2.65 |
| Ceiling sold price (call) | 40,000 | April 2019 – June 2019 | $ 2.84 |
| Floor sold price (put) | 40,000 | April 2019 – June 2019 | $ 2.30 |
| Floor purchase price (put) | 20,000 | January 2020 – June 2020 | $ 2.70 |
| Ceiling sold price (call) | 20,000 | January 2020 – June 2020 | $ 3.05 |
| Floor sold price (put) | 20,000 | January 2020 – June 2020 | $ 2.25 |
| Floor purchase price (put) | 30,000 | October 2019 – June 2020 | $ 2.90 |
| Ceiling sold price (call) | 30,000 | October 2019 – June 2020 | $ 3.15 |
| Floor sold price (put) | 30,000 | October 2019 – June 2020 | $ 2.50 |
| **Natural Gas Call/Put Options:** | | | |
| Call sold | 15,000 | January 2019 – March 2019 | $ 3.50 |
| **Basis Swaps:** | | | |
| Appalachia - Dominion | 17,500 | January 2019 – December 2019 | $ (0.50) |
| Appalachia - Dominion | 20,000 | April 2019 – March 2020 | $ (0.39) |

*Oil:*

| Description | Volume (Bbls/d) | Production Period | Weighted Average Price ($/Bbl) |
|---|---|---|---|
| **Oil Swaps:** | | | |
| | 1,000 | July 2019 – December 2019 | $ 58.80 |
| | 500 | January 2020 – December 2020 | $ 58.20 |
| **Oil Collars:** | | | |
| Floor purchase price (put) | 1,000 | July 2019 – December 2019 | $ 50.00 |
| Ceiling sold price (call) | 1,000 | July 2019 – December 2019 | $ 66.75 |
| Floor purchase price (put) | 500 | January 2020 – December 2020 | $ 50.00 |
| Ceiling sold price (call) | 500 | January 2020 – December 2020 | $ 64.00 |

*NGL:*

| Description | Volume (Gal/d) | Production Period | Weighted Average Price ($/Gal) |
|---|---|---|---|
| **Propane Swaps:** | | | |
| | 46,200 | January 2019 – March 2019 | $ 0.74 |
| | 14,700 | January 2019 – December 2019 | $ 0.95 |

### Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of natural gas and oil properties and repayment of principal and interest on outstanding debt. The Board of Directors recently approved an initial capital budget for 2019 of between approximately $375 - $400 million, allocated approximately 90% for drilling and completions activities and approximately 10% for land activities and other capital requirements. The 2019 capital budget is expected to be substantially funded through internally generated cash flows, the Company's current cash balance and borrowings under the revolving credit facility. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas, NGLs and oil prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in natural gas, NGLs or oil prices from current levels may result in a further decrease in our actual capital expenditures, which would negatively impact our ability to grow production and our proved reserves as well as our ability to maintain compliance with our debt covenants. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities, additional borrowings under our revolving credit facility or the sale of assets.

In addition, we may from time to time seek to pay down, retire or repurchase our outstanding debt using cash or through exchanges of other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on available funds, prevailing market conditions, our liquidity requirements, contractual restrictions in our revolving credit agreement and other factors.

### Capitalization

As of December 31, 2018 and 2017, our total debt, excluding debt discount and issuance costs, and capitalization were as follows (in millions):

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Senior unsecured notes | $ 510.5 | $ 510.5 |
| Credit facility | 32.5 | — |
| Stockholders' equity | 687.5 | 572.4 |
| Total capitalization | $ 1,230.5 | $ 1,082.9 |

### Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, firm transportation, gas processing, gathering and compressions services, and asset retirement obligations. As of December 31, 2018 and 2017, we did not have any capital leases, any significant off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed any debt of any unrelated party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2018. In addition to the contractual obligations listed in the table below, our balance sheet at December 31, 2018 reflects accrued interest payable of $21.7 million, compared to $21.1 million as of December 31, 2017. We paid the accrued interest balance in January 2019.

The following summarizes our contractual financial obligations at December 31, 2018 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our revolving credit facility, additional debt and equity issuances, proceeds from our drilling joint venture and proceeds from asset sales (in thousands):

| | 2019 | 2020 | 2021 | 2022 | 2023 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Senior unsecured notes[(1)] | $ — | $ — | $ — | $ — | $ 510,465 | $ — | $ 510,465 |
| Drilling rig commitments[(2)] | 1,287 | — | — | — | — | — | 1,287 |
| Firm transportation[(3)] | 80,083 | 80,303 | 80,083 | 80,083 | 80,083 | 700,549 | 1,101,184 |
| Gas processing, gathering, and compression services[(4)] | 26,271 | 22,886 | 18,147 | 20,440 | 18,515 | 61,923 | 168,182 |
| Asset retirement obligation liability[(5)] | — | — | — | — | — | 7,110 | 7,110 |
| Operating leases | 1,360 | 1,060 | 929 | 755 | 755 | 1,619 | 6,478 |
| Vehicle loans | 332 | 93 | 65 | 55 | 31 | 6 | 582 |
| | $ 109,333 | $ 104,342 | $ 99,224 | $ 101,333 | $ 609,849 | $ 771,207 | $1,795,288 |

(1) The ultimate settlement amount and timing cannot be precisely determined in advance. See Note 7— *Debt* to our consolidated financial statements as of and for the year ended December 31, 2018.

(2) We had contracts for the service of two rigs, which have both expired and we are currently on well-to-well contracts. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest, as applicable.

(3) We have entered into firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit us to transport minimum daily natural gas volumes at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(4) Contractual commitments for gas processing, gathering and compression service agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression agreements. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(5) Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

### Other

We lease acreage that is generally subject to lease expiration if operations are not commenced within a specified period, generally 5 years and approximately 64% of our leases in the Utica Core Area have a 3-5 year extension at our option. Based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

### Interest Rates

At December 31, 2018 and 2017, we had $510.5 million of senior unsecured notes outstanding, excluding discounts, which bore interest at a fixed cash interest rate of 8.875% and was due semi-annually from the date of issuance.

Information related to our interest rates is described in Note 7— *Debt* to our consolidated financial statements and is incorporated herein by reference.

## Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments which are described above under "—Cash Contractual Obligations".

## Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, it does not normally have a significant effect on our business. We expect costs in fiscal 2019 to continue to be a function of supply and demand. Further strengthening of commodity prices could stimulate demand for ancillary services causing services costs to increase. In the near term, the majority of our service costs are expected to remain flat in 2019 due to previously negotiated drilling, stimulation, and rentals contracts. Along with these contacts, we have secured quality service equipment and tenured personnel to limit our exposure to increasing service costs and improve operational efficiencies.

## Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and proved natural gas and oil reserves. Some accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

### *Natural Gas and Oil Properties*

We follow the successful efforts method of accounting for natural gas and oil producing activities. Unsuccessful exploration drilling costs are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and audited by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, NGLs, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are economically recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, including the rule revisions designed to modernize the oil and gas company reserves reporting requirements which were adopted effective December 31, 2009, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas, NGLs and oil prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Manager, Reserves Reporting who reports directly to our Chief Operating Officer. To further ensure the reliability of our reserve estimates, we engage independent petroleum engineers to prepare our estimates of proved reserves at least annually. SIS, our independent petroleum engineers for the year ended December 31, 2018, prepared 100% of our reserves in 2018 and NSAI, our independent petroleum engineers, for all prior years, prepared 100% of our reserves in 2017, 2016, 2015 and 2014. For additional discussion, “See Items 1 and 2. Business and Properties—Oil and Natural Gas Data—Proved Reserves”.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Estimated reserves are used as the basis for calculating the expected future cash flows from property asset groups, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 18— *Supplemental Oil and Gas Information* to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis.

We monitor our long-lived assets recorded in natural gas and oil properties in our consolidated balance sheets to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas, NGLs and oil prices, an estimate of the ultimate amount of recoverable natural gas, NGLs and oil reserves that will be produced from the property asset groups future production, future production costs, future abandonment costs, and future inflation. The need to test a property asset group for impairment can be based on several factors, including a significant reduction in sales prices for natural gas, NGLs and/or oil, unfavorable adjustments to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts or environmental regulations. Our natural gas and oil properties are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. All of these factors must be considered when testing a property asset group carrying value for impairment.

The review is done by determining if the historical cost of proved and unproved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated undiscounted future net cash flows. The expected undiscounted future net cash flows are estimated based on our plans to produce and develop reserves. Expected undiscounted future net cash inflows from the sale of produced reserves are calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable reserves, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of undiscounted future cash flows. When the carrying value exceeds the sum of undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. We cannot predict whether impairment charges may be required in the future.

We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leaseholds. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Potential impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors.

### *Acquisitions*

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

### *Asset Retirement Obligations*

We have significant obligations to remove tangible equipment and restore land at the end of natural gas and oil production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation ("ARO"), a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment in formation, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, a component of depreciation, depletion and amortization in the accompanying consolidated statements of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

### *Revenue Recognition*

Information related to revenue recognition is described in Note 2— *Summary of Significant Accounting Policies* to our consolidated financial statements and is incorporated herein by reference.

## Recent Accounting Pronouncements

Information related to recent accounting pronouncements is described in Note 2— *Summary of Significant Accounting Policies* to our consolidated financial statements and is incorporated herein by reference.

## Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

## Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Natural gas prices affect us more than oil prices because approximately 82% and 75% of our proved reserves as of December 31, 2018 and 2017, respectively, were natural gas.

For a discussion of how we use financial commodity derivative contracts to mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Commodity Hedging Activities."

The following table shows the fair value of our commodity derivatives and the hypothetical change in fair value that would result from a 10% change in commodity prices at December 31, 2018:

| | Fair Value | Hypothetical 10% Increase in Commodity Price | Hypothetical 10% Decrease in Commodity Price |
|---|---|---|---|
| Natural Gas | $ 401 | $ 16,766 | $ 15,247 |
| NGLs | — | — | — |
| Oil | 5,298 | 2,723 | 2,383 |

**Interest Rate Risk**

On July 6, 2015, we issued $550 million in aggregate principal amount of 8.875% senior unsecured notes due 2023 at an issue price of 97.903% of the principal amount of the senior unsecured notes, plus accrued and unpaid interest, if any. At December 31, 2018, the cash interest rate with respect to the senior unsecured notes was fixed at 8.875% and was due semi-annually from the date of issuance.

During the year ended December 31, 2016, the Company repurchased $39.5 million of the outstanding senior unsecured notes in open market purchases for $23.4 million. The principal of the outstanding senior unsecured notes that were repurchased less cash proceeds and unamortized debt discount and deferred financing costs were charged to gain on early extinguishment of debt, totaling $14.5 million for the year ended December 31, 2016. The Company repurchased all such senior unsecured notes with cash on hand.

We will be exposed to interest rate risk to the extent we draw on our revolving credit facility. Interest on outstanding borrowings under our revolving credit facility will accrue based on, at our option, LIBOR or the alternate base rate, in each case, plus an applicable margin that is determined based on our utilization of commitments under our revolving credit facility. As of December 31, 2018, the borrowing base was $225 million and we had $32.5 million in outstanding borrowings. After giving effect to our outstanding letters of credit, totaling $27.0 million, we had available borrowing capacity under the revolving credit facility of $165.5 million at December 31, 2018.

In connection with the closing of the BRMR Merger, we amended and restated the credit agreement governing our revolving credit facility in order to, among other things, increase the borrowing base from $225 million to approximately $375 million and extend the maturity date thereof to approximately five years after the closing of the BRMR Merger.

Subsequent to December 31, 2018, we reduced our outstanding letters of credit to approximately $13.5 million. Further, we borrowed an incremental $85 million under our revolving credit facility, which reduced the available borrowing capacity under such facility to $244 million.

**Counterparty and Customer Credit Risk**

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts, the sale of our oil and gas production, which we market to energy companies, end users and refineries, and joint interest receivables.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, 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. The creditworthiness of our counterparties is subject to periodic review. As of December 31, 2018, we had economic hedges in place with six counterparties. The fair value of our commodity derivative contracts of approximately $5.7 million at December 31, 2018 includes the following values by bank counterparty: Bank of Montreal $3.1 million; KeyBank N.A. $0.4 million; Morgan Stanley ($0.3) million; Capital One N.A. $0.1 million; BP Energy Company $1.9 million; and Goldman Sachs $0.5 million. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at December 31, 2018 for each of the banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by our revolving credit facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2018, we did not have past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to concentration of our receivables from several significant customers for sales of natural gas. We, generally, do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells.

## Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required for this Item are set forth beginning on page F-1 of this report and are incorporated herein by reference.

## Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable

## Item 9A. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

The Company’s management carried out an evaluation (as required by Rule 13a-15(b) of the Exchange Act), with the participation of the Company’s President and Chief Executive Officer and Executive Vice President and Chief Financial Officer, of the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act), as of the end of the period covered by this Annual Report. Based upon this evaluation, the Company’s President and Chief Executive Officer and Executive Vice President and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of the end of the period covered by this Annual Report, such that the information relating to the Company and its consolidated subsidiaries required to be disclosed by the Company in the reports that it files or submits under the Exchange Act (i) is recorded, processed, summarized, and reported, within the time periods specified in the SEC’s rules and forms, and (ii) is accumulated and communicated to the Company’s management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

### Changes in Internal Controls

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15(d)-15(f) under the Exchange Act) during the fourth quarter of 2018 that has materially affected, or is reasonable likely to materially affect, the Company’s internal control over financial reporting.

## Management's Annual Report on Internal Control Over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system is designed to provide reasonable assurance to its management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. All internal control systems, no matter how well designed, have inherent limitations. Accordingly, even effective controls can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of its internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework* (2013). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2018.

This Annual Report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.

## Item 9B. Other Information

Not applicable.

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

### Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

### Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

### Item 13. Certain Relationships and Related Transactions, and Director Independence

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

### Item 14. Principal Accounting Fees and Services

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2019 Annual Meeting of Stockholders.

# PART IV

## Item 15. Exhibits, Financial Statement Schedules

(1) Financial Statements:

The consolidated financial statements are listed on the Index to Financial Statements to this report beginning on page F-1.

(2) Financial Statement Schedules:

No financial statement schedules are submitted because of the absence of the conditions under which they are required, the required information is insignificant or because the required information is included in the consolidated financial statements.

(3) Exhibits:

The following exhibits are filed as part of this Annual Report.

## EXHIBIT INDEX

| Exhibit No. | Description |
|---|---|
| 2.1# | Purchase and Sale Agreement, dated December 8, 2017, between Travis Peak Resources, LLC, Eclipse Resources-PA, LP, and Eclipse Resources Corporation (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on December 12, 2017). |
| 2.2# | Option Agreement, dated as of December 8, 2017, by and among Cardinal Midstream II, LLC, Cardinal NE Holdings, LLC, Cardinal NE Midstream, LLC, Eclipse Resources Corporation, Eclipse Resources Midstream, LP, and Eclipse Resources-PA, LP (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K filed with the SEC on December 12, 2017). |
| 2.3# | Participation Agreement, dated December 22, 2017, by and among Eclipse Resources I, LP, Eclipse Resources-Ohio, LLC, and SEG-ECR LLC (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on December 28, 2017). + |
| 2.4# | Agreement and Plan of Merger, dated as of August 25, 2018, among Eclipse Resources Corporation, Everest Merger Sub, Inc., and Blue Ridge Mountain Resources, Inc. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |
| 2.5 | Amendment No. 1 to Agreement and Plan of Merger, dated as of January 7, 2019, among Eclipse Resources Corporation, Everest Merger Sub Inc., and Blue Ridge Mountain Resources, Inc. (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K filed with the SEC on January 7, 2019). |
| 3.1 | Second Amended and Restated Certificate of Incorporation of Montage Resources Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on March 6, 2019). |
| 3.2 | Second Amended and Restated Bylaws of Montage Resources Corporation (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed with the SEC on March 6, 2019). |
| 3.3 | Certificate of Ownership and Merger, filed with the Secretary of State of the State of Delaware with an effective date of February 28, 2019 (incorporated by reference to Exhibit 3.3 to the Company's Current Report on Form 8-K filed with the SEC on March 6, 2019). |
| 4.1 | Amended and Restated Registration Rights Agreement, dated January 28, 2015, by and among Eclipse Resources Corporation, Eclipse Resources Holdings, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P., EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., Eclipse Management, L.P., Buckeye Investors L.P., GSO Capital Opportunities Fund II (Luxembourg) S.à.r.l., Fir Tree Value Master Fund, L.P., Luxor Capital Partners, LP and Luxor Capital Partners Offshore Master Fund, LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 29, 2015). |
| 4.2* | Specimen Common Stock Certificate of Montage Resources Corporation. |
| 4.3 | Indenture, dated as of July 6, 2015, between Eclipse Resources Corporation, the guarantors party thereto and Deutsche Bank Trust Company Americas, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on July 8, 2015). |
| 4.4 | Registration Rights Agreement, dated as of January 18, 2018, by and among Eclipse Resources Corporation, Eclipse Resources-PA, LP, and Travis Peak Resources, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 22, 2018). |
| 10.1 | Second Amended and Restated Credit Agreement, dated as of June 11, 2015, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on June 12, 2015). |

| Exhibit No. | Description |
|---|---|
| 10.2 | First Amendment to Second Amended and Restated Credit Agreement, dated January 21, 2016, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 25, 2016). |
| 10.3 | Second Amendment to Second Amended and Restated Credit Agreement, dated as of February 24, 2016, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on February 26, 2016). |
| 10.4 | Third Amendment to Second Amended and Restated Credit Agreement, dated as of February 24, 2017, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on March 2, 2017). |
| 10.5 | Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of August 1, 2017, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on August 7, 2017). |
| 10.6 | Third Amended and Restated Credit Agreement, dated as of February 28, 2019, among Montage Resources Corporation, Bank of Montreal, as administrative agent, the lenders party thereto, and BMO Capital Markets Corp., Capital One, National Association, and KeyBank National Association, as joint lead arrangers and joint bookrunners (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on March 6, 2019). |
| 10.7† | Eclipse Resources Corporation 2014 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014). |
| 10.8† | Eclipse Resources Corporation 2014 Long-Term Incentive Plan, as amended by the First Amendment (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on May 18, 2017). |
| 10.9 | Master Reorganization Agreement, dated June 6, 2014, by and among Eclipse Resources I, LP, Eclipse GP, LLC, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P., Eclipse Management, L.P., Eclipse Resources Holdings, L.P., Eclipse Resources Corporation and Benjamin W. Hulburt, Christopher K. Hulburt and Thomas S. Liberatore (incorporated by reference to Exhibit 10.9 to Amendment No. 2 to the Company's Registration Statement on Form S-1 filed with the SEC on June 9, 2014). |
| 10.10† | Form of Indemnification Agreement for Eclipse Resources Corporation Officers and Directors (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to the Company's Registration Statement on Form S-1 filed with the SEC on June 2, 2014). |
| 10.11† | Amended and Restated Executive Employment Agreement, dated as of August 17, 2017, by and between Eclipse Resources Corporation and Benjamin W. Hulburt (incorporated by referenced to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on August 18, 2017). |
| 10.12† | Amended and Restated Executive Employment Agreement, dated as of August 17, 2017, by and between Eclipse Resources Corporation and Matthew R. DeNezza (incorporated by referenced to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on August 18, 2017). |
| 10.13† | Amended and Restated Executive Employment Agreement, dated as of August 17, 2017, by and between Eclipse Resources Corporation and Christopher K. Hulburt (incorporated by referenced to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on August 18, 2017). |

| Exhibit No. | Description |
|---|---|
| 10.14† | Amended and Restated Executive Employment Agreement, dated as of January 1, 2017, by and between Eclipse Resources Corporation and Oleg Tolmachev (incorporated by referenced to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 3, 2017). |
| 10.15 | Securities Purchase Agreement, dated as of December 27, 2014, by and between Eclipse Resources Corporation, CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P., EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., Buckeye Investors L.P., GSO Capital Opportunities Fund II L.P., GSO Eclipse Holdings I LP, Fir Tree Value Master Fund, L.P., Luxor Capital Partners, LP and Luxor Capital Partners Offshore Master Fund, LP. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on December 29, 2014). |
| 10.16† | Form of Restricted Stock Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on March 2, 2016). |
| 10.17† | Form of Performance Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on March 2, 2016). |
| 10.18† | Form of Restricted Stock Unit Award Agreement for 2015 Bonuses (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on March 2, 2016). |
| 10.19† | Form of Performance Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on April 26, 2016). |
| 10.20 | Voting Agreement, dated as of August 25, 2018, among Eclipse Resources Corporation, Blue Ridge Mountain Resources, Inc., and the stockholders of Blue Ridge Mountain Resources, Inc. party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |
| 10.21 | Voting Agreement, dated as of August 25, 2018, among Eclipse Resources Corporation, Blue Ridge Mountain Resources, Inc., and the stockholders of Eclipse Resources Corporation party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |
| 10.22 | Lock-Up Agreement, dated as of August 25, 2018, from the stockholders of Eclipse Resources Corporation party thereto (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |
| 10.23 | Form of Lock-Up Agreement from the stockholders of Blue Ridge Mountain Resources, Inc. party thereto (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |
| 10.24 | Board Observation Agreement, dated as of August 25, 2018, by and among Eclipse Resources Corporation, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., and EnCap Energy Capital Fund IX, L.P. (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |
| 10.25† | Separation and Release Agreement, dated as of August 24, 2018, by and between Eclipse Resources Corporation and Benjamin W. Hulburt (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |
| 10.26† | Separation and Release Agreement, dated as of August 24, 2018, by and between Eclipse Resources Corporation and Matthew R. DeNezza (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |
| 10.27† | Separation and Release Agreement, dated as of August 24, 2018, by and between Eclipse Resources Corporation and Christopher K. Hulburt (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K filed with the SEC on August 27, 2018). |

| Exhibit No. | Description |
|---|---|
| 10.28† | Amendment to Separation and Release Agreement, dated as of November 30, 2018, by and between Eclipse Resources Corporation and Matthew R. DeNezza (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on December 4, 2018). |
| 21.1* | List of Subsidiaries of Montage Resources Corporation |
| 23.1* | Consent of Grant Thornton LLP |
| 23.2* | Consent of Software Integrated Solutions Division of Schlumberger Technology Corporation |
| 31.1* | Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241) |
| 31.2* | Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241) |
| 32.1** | Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350) |
| 32.2** | Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350) |
| 99.1* | Software Integrated Solutions Division of Schlumberger Technology Corporation, Summary of Reserves for Unconventional Properties as of December 31, 2018 (Eclipse Resources Corporation). |
| 99.2 | Netherland Sewell & Associates, Inc., Summary of Reserves for Unconventional Properties as of December 31, 2017 (Eclipse Resources Corporation) (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K filed with the SEC on March 2, 2018). |
| 99.3 | Netherland Sewell & Associates, Inc., Summary of Reserves for Unconventional Properties as of December 31, 2016 (Eclipse Resources Corporation) (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K filed with the SEC on March 3, 2017). |
| 101.INS* | XBRL Instance Document |
| 101.SCH* | XBRL Taxonomy Extension Schema Document |
| 101.CAL* | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF* | XBRL Taxonomy Extension Definition Linkbase Document |
| 101.LAB* | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE* | XBRL Taxonomy Extension Presentation Linkbase Document |

\# Pursuant to Item 601(b)(2) of Regulation S-K, certain schedules and similar attachments to this agreement have been omitted. The registrant hereby agrees to furnish supplementally a copy of any omitted schedule or similar attachment to the Securities and Exchange Commission upon request.

* Filed herewith.

** These exhibits are furnished herewith and shall not be deemed "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act.

\+ Confidential treatment has been granted for certain portions of this Exhibit pursuant to Rule 24b-2 of the Exchange Act, which portions have been omitted and filed separately with the Securities and Exchange Commission.

† Management contract or compensatory plan or arrangement.

**Item 16. Form 10-K Summary**

None.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

March 15, 2019

MONTAGE RESOURCES CORPORATION
(Registrant)

/s/ John K. Reinhart
John K. Reinhart
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant in the capacities and on the dates indicated.

| Signature | Date |
|---|---|
| /s/ John K. Reinhart<br>John K. Reinhart<br>President, Chief Executive Officer and Director | March 15, 2019 |
| /s/ Michael Hodges<br>Michael Hodges<br>Executive Vice President and Chief Financial Officer | March 15, 2019 |
| /s/ Todd R. Bart<br>Todd R. Bart<br>Vice President and Chief Accounting Officer | March 15, 2019 |
| /s/ Michael C. Jennings<br>Michael C. Jennings<br>Chairman | March 15, 2019 |
| /s/ Randall M. Albert<br>Randall M. Albert<br>Director | March 15, 2019 |
| /s/ Robert L. Zorich<br>Robert L. Zorich<br>Director | March 15, 2019 |
| /s/ Douglas E. Swanson, Jr.<br>Douglas E. Swanson, Jr.<br>Director | March 15, 2019 |
| /s/ Mark E. Burroughs, Jr.<br>Mark E. Burroughs, Jr.<br>Director | March 15, 2019 |
| /s/ Eugene I. Davis<br>Eugene I. Davis<br>Director | March 15, 2019 |
| /s/ Richard Paterson<br>Richard Paterson<br>Director | March 15, 2019 |
| /s/ Don Dimitrievich<br>Don Dimitrievich<br>Director | March 15, 2019 |
| /s/ D. Martin Phillips<br>D. Martin Phillips<br>Director | March 15, 2019 |

## INDEX TO FINANCIAL STATEMENTS

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Montage Resources Corporation

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Montage Resources Corporation (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2018 and 2017, the related consolidated statements of comprehensive income, changes in stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company’s auditor since 2011.

Pittsburgh, Pennsylvania
March 15, 2019

**MONTAGE RESOURCES CORPORATION**
**CONSOLIDATED BALANCE SHEETS**
**(in thousands, except share and per share data)**

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| **ASSETS** | | |
| **CURRENT ASSETS** | | |
| Cash and cash equivalents | $ 5,959 | $ 17,224 |
| Accounts receivable | 119,332 | 77,609 |
| Assets held for sale | — | 206 |
| Other current assets | 8,639 | 12,023 |
| Total current assets | 133,930 | 107,062 |
| **PROPERTY AND EQUIPMENT** | | |
| Oil and natural gas properties, successful efforts method: | | |
| Unproved properties | 482,475 | 459,549 |
| Proved oil and gas properties, net | 807,583 | 647,881 |
| Other property and equipment, net | 6,300 | 6,942 |
| Total property and equipment, net | 1,296,358 | 1,114,372 |
| **OTHER NONCURRENT ASSETS** | | |
| Other assets | 3,481 | 2,093 |
| **TOTAL ASSETS** | **$ 1,433,769** | **$ 1,223,527** |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| **CURRENT LIABILITIES** | | |
| Accounts payable | $ 116,735 | $ 76,174 |
| Accrued capital expenditures | 12,979 | 10,658 |
| Accrued liabilities | 56,909 | 41,662 |
| Accrued interest payable | 21,661 | 21,100 |
| Total current liabilities | 208,284 | 149,594 |
| **NONCURRENT LIABILITIES** | | |
| Debt, net of unamortized discount and debt issuance costs | 497,778 | 495,021 |
| Credit facility | 32,500 | — |
| Asset retirement obligations | 7,110 | 6,029 |
| Other liabilities | 611 | 529 |
| Total liabilities | 746,283 | 651,173 |
| **COMMITMENTS AND CONTINGENCIES** | | |
| **STOCKHOLDERS' EQUITY** | | |
| Preferred stock, 50,000,000 authorized, no shares issued and outstanding | — | — |
| Common stock, $0.01 par value, 1,000,000,000 authorized, 20,169,063 and 17,516,024 shares issued and outstanding, respectively | 3,043 | 2,637 |
| Additional paid in capital | 2,065,119 | 1,967,958 |
| Treasury stock, shares at cost; 1,747,624 and 992,315 shares, respectively | (3,357) | (2,096) |
| Accumulated deficit | (1,377,319) | (1,396,145) |
| Total stockholders' equity | 687,486 | 572,354 |
| **TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY** | **$ 1,433,769** | **$ 1,223,527** |

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

## MONTAGE RESOURCES CORPORATION
## CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
**(in thousands except per share data)**

| | For the Year Ended December 31, 2018 | 2017 | 2016 |
|---|---|---|---|
| **REVENUES** | | | |
| Natural gas, oil and natural gas liquids sales | $ 498,593 | $ 380,178 | $ 223,015 |
| Brokered natural gas and marketing revenue | 16,552 | 3,481 | 12,019 |
| Total revenues | 515,145 | 383,659 | 235,034 |
| **OPERATING EXPENSES** | | | |
| Lease operating | 28,289 | 20,525 | 9,023 |
| Transportation, gathering and compression | 138,766 | 124,839 | 109,226 |
| Production and ad valorem taxes | 10,141 | 8,490 | 7,927 |
| Brokered natural gas and marketing expense | 16,886 | 3,191 | 12,268 |
| Depreciation, depletion and amortization | 134,277 | 118,818 | 92,948 |
| Exploration | 49,563 | 50,208 | 52,775 |
| General and administrative | 44,389 | 44,553 | 39,431 |
| Rig termination and standby | — | 1 | 3,846 |
| Impairment of proved oil and gas properties | — | — | 17,665 |
| Accretion of asset retirement obligations | 663 | 544 | 391 |
| (Gain) loss on sale of assets | (1,815) | (179) | 6,936 |
| Total operating expenses | 421,159 | 370,990 | 352,436 |
| **OPERATING INCOME (LOSS)** | **93,986** | **12,669** | **(117,402)** |
| **OTHER INCOME (EXPENSE)** | | | |
| Gain (loss) on derivative instruments | (21,169) | 45,365 | (52,338) |
| Interest expense, net | (53,990) | (49,490) | (50,789) |
| Gain (loss) on early extinguishment of debt | — | — | 14,489 |
| Other income (expense) | (1) | (19) | (149) |
| Total other income (expense), net | (75,160) | (4,144) | (88,787) |
| **INCOME (LOSS) BEFORE INCOME TAXES** | **18,826** | **8,525** | **(206,189)** |
| **INCOME TAX BENEFIT (EXPENSE)** | — | — | (546) |
| **NET INCOME (LOSS)** | **$ 18,826** | **$ 8,525** | **$ (206,735)** |
| **NET INCOME (LOSS) PER COMMON SHARE (See Note 11)** | | | |
| Basic | **$ 0.94** | **$ 0.49** | **$ (12.84)** |
| Diluted | **$ 0.94** | **$ 0.48** | **$ (12.84)** |
| **WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (See Note 11)** | | | |
| Basic | **19,999** | **17,479** | **16,096** |
| Diluted | **20,087** | **17,679** | **16,096** |

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

**MONTAGE RESOURCES CORPORATION**
**CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY**
**FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, and 2016**
**(in thousands, except share and per share data)**

| | Number of Shares | Common Stock ($0.01 Par) | Additional Paid-in-Capital | Treasury Stock | Accumulated Deficit | Total |
|---|---|---|---|---|---|---|
| **Balances, December 31, 2015** | 14,844,951 | $ 2,227 | $1,829,082 | $ — | $(1,197,935) | $ 633,374 |
| Stock-based compensation | — | — | 6,216 | — | — | 6,216 |
| Shares of common stock issued in public offering, net of equity issuance costs | 2,500,000 | 375 | 123,438 | — | — | 123,813 |
| Issuance of restricted stock | 9,963 | 2 | (2) | — | — | — |
| Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income tax withholdings | 17,878 | 3 | (3) | (61) | — | (61) |
| Net loss | — | — | — | — | (206,735) | (206,735) |
| **Balances, December 31, 2016** | 17,372,793 | $ 2,607 | $1,958,731 | $ (61) | $(1,404,670) | $ 556,607 |
| Stock-based compensation | — | — | 9,301 | — | — | 9,301 |
| Equity issuance costs | — | — | (44) | — | — | (44) |
| Issuance of restricted stock | 10,213 | 2 | (2) | — | — | — |
| Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income tax withholdings | 133,018 | 28 | (28) | (2,035) | — | (2,035) |
| Net income | — | — | — | — | 8,525 | 8,525 |
| **Balances, December 31, 2017** | 17,516,024 | $ 2,637 | $1,967,958 | $ (2,096) | $(1,396,145) | $ 572,354 |
| Stock-based compensation | — | — | 7,891 | — | — | 7,891 |
| Equity issuance costs | — | — | (344) | — | — | (344) |
| Shares of common stock issued in asset acquisition, net of equity issuance costs | 2,521,573 | 378 | 89,642 | — | — | 90,020 |
| Issuance of restricted stock | 15,476 | 2 | (2) | — | — | — |
| Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income tax withholdings | 115,990 | 26 | (26) | (1,261) | — | (1,261) |
| Net income (loss) | — | — | — | — | 18,826 | 18,826 |
| **Balances, December 31, 2018** | 20,169,063 | $ 3,043 | $2,065,119 | $ (3,357) | $(1,377,319) | $ 687,486 |

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

**MONTAGE RESOURCES CORPORATION**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in thousands)**

| | For the Year Ended December 31, 2018 | 2017 | 2016 |
|---|---|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES** | | | |
| Net income (loss) | $ 18,826 | $ 8,525 | $ (206,735) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities | | | |
| Depreciation, depletion and amortization | 134,277 | 118,818 | 92,948 |
| Exploration expense | 28,324 | 31,417 | 30,853 |
| Stock-based compensation | 7,891 | 9,301 | 6,216 |
| Impairment of proved oil and gas properties | — | — | 17,665 |
| Accretion of asset retirement obligations | 663 | 544 | 391 |
| (Gain) loss on derivative instruments | 21,169 | (45,365) | 52,338 |
| Net cash receipts (payments) on settled derivatives | (26,985) | (2,224) | 38,696 |
| (Gain) loss on sale of assets | (1,815) | (179) | 6,936 |
| (Gain) loss on early extinguishment of debt | — | — | (14,489) |
| Deferred income taxes | — | — | 540 |
| Amortization of deferred financing costs | 2,256 | 2,098 | 1,962 |
| Amortization of debt discount | 1,327 | 1,324 | 1,362 |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | (42,879) | (31,780) | (21,277) |
| Other assets | (2,192) | 1,863 | (1,795) |
| Accounts payable and accrued liabilities | 84,231 | 18,404 | 794 |
| Net cash provided by operating activities | 225,093 | 112,746 | 6,405 |
| **CASH FLOWS FROM INVESTING ACTIVITIES** | | | |
| Capital expenditures for oil and gas properties | (275,601) | (291,779) | (167,355) |
| Capital expenditures for other property and equipment | (1,007) | (2,007) | (1,164) |
| Proceeds from sale of assets | 10,358 | 1,317 | 79,201 |
| Net cash used in investing activities | (266,250) | (292,469) | (89,318) |
| **CASH FLOWS FROM FINANCING ACTIVITIES** | | | |
| Debt issuance costs | (497) | (1,750) | 30 |
| Repayments of long-term debt | (506) | (453) | (24,045) |
| Proceeds from issuance of common stock | — | — | 124,361 |
| Proceeds from credit facility | 32,500 | — | — |
| Equity issuance costs | (344) | (44) | (548) |
| Employee tax withholding for settlement of equity compensation awards | (1,261) | (2,035) | (61) |
| Net cash provided by (used in) financing activities | 29,892 | (4,282) | 99,737 |
| Net increase (decrease) in cash and cash equivalents | (11,265) | (184,005) | 16,824 |
| Cash and cash equivalents at beginning of period | 17,224 | 201,229 | 184,405 |
| Cash and cash equivalents at end of period | $ 5,959 | $ 17,224 | $ 201,229 |
| **SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION** | | | |
| Cash paid for interest | $ 51,101 | $ 47,362 | $ 48,483 |
| **SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES** | | | |
| Asset retirement obligations incurred, including changes in estimate | $ 418 | $ 679 | $ 1,014 |
| Additions of other property through debt financing | $ 173 | $ 183 | $ — |
| Additions to oil and natural gas properties - changes in accounts payable, accrued liabilities, and accrued capital expenditures | $ (15,269) | $ 22,264 | $ 8,583 |
| Assets held for sale | $ — | $ (262) | $ — |
| Asset acquisition through stock issuance | $ 90,020 | $ — | $ — |

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

**MONTAGE RESOURCES CORPORATION**
**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS**
**FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, and 2016**

## Note 1—Organization and Nature of Operations

Montage Resources Corporation (the "Company"), is an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin of the United States, which encompasses the Utica Shale, Indian Castle/Flat Creek Shales and Marcellus Shale prospective areas.

## Note 2—Summary of Significant Accounting Policies

### *(a) Basis of Presentation*

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). In the opinion of management, the accompanying consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of December 31, 2018 and 2017, and the results of its operations, comprehensive income (loss) and its cash flows for the years ended December 31, 2018, 2017, and 2016.

### *(b) Cash and Cash Equivalents*

Cash and cash equivalents are comprised of cash in banks and highly liquid instruments with original maturities of three months or less, primarily consisting of bank time deposits and investments in institutional money market funds. The carrying amounts approximate fair value due to the short-term nature of these items. Cash in bank accounts at times may exceed federally insured limits.

### *(c) Accounts Receivable*

Accounts receivable are carried at estimated net realizable value. Receivables deemed uncollectible are charged directly to expense. Trade credit is generally extended on a short-term basis, and therefore, accounts receivable do not bear interest, although a finance charge may be applied to such receivables that are past due. A valuation allowance is provided for those accounts for which collection is estimated as doubtful and uncollectible accounts are written off and charged against the allowance. In estimating the allowance, management considers, among other things, how recently and how frequently payments have been received and the financial position of the party. The Company did not deem any of its accounts receivables to be uncollectable as of December 31, 2018 or December 31, 2017.

The Company accrues revenue due to timing differences between the delivery of natural gas, NGLs, and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Company's records and management's estimates of the related commodity sales and transportation and compression fees, which are, in turn, based upon applicable product prices. The Company had $94.1 million and $52.9 million of accrued revenues, net of expenses at December 31, 2018 and December 31, 2017, respectively, which were included in accounts receivable within the Company's consolidated balance sheets.

### *(d) Property and Equipment*

*Oil and Natural Gas Properties*

The Company follows the successful efforts method of accounting for its oil and natural gas operations. Acquisition costs for oil and natural gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense (see " *Depreciation, Depletion and Amortization* " below).

Costs incurred to acquire producing and non-producing leaseholds are capitalized. All unproved leasehold acquisition costs are initially capitalized, including the cost of leasing agents, title work and due diligence. If the Company acquires leases in a prospective area, these costs are capitalized as unproved leasehold costs. If no leases are acquired by the Company with respect to the initial costs incurred or the Company discontinues leasing in a prospective area, the costs are charged to exploration expense. Unproved leasehold costs that are determined to have proved oil and gas reserves are transferred to proved leasehold costs.

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to the Company's consolidated statements of operations. Upon the sale of an individual well, the proceeds are credited to accumulated depreciation and depletion within the Company's consolidated balance sheets. Upon the sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in the Company's consolidated statements of operations. Upon the sale of an entire interest in an unproved property where the property had been assessed for impairment on a group basis, no gain or loss is recognized in the Company's consolidated statements of operations unless the proceeds exceed the original cost of the property, in which case a gain is recognized in the amount of such excess. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

A summary of property and equipment including oil and natural gas properties is as follows (in thousands):

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Oil and natural gas properties: | | |
| Unproved | $ 482,475 | $ 459,549 |
| Proved | 2,188,233 | 1,896,081 |
| Gross oil and natural gas properties | 2,670,708 | 2,355,630 |
| Less accumulated depreciation, depletion and amortization | (1,380,650) | (1,248,200) |
| Oil and natural gas properties, net | 1,290,058 | 1,107,430 |
| Other property and equipment | 14,460 | 13,508 |
| Less accumulated depreciation | (8,160) | (6,566) |
| Other property and equipment, net | 6,300 | 6,942 |
| Property and equipment, net | $ 1,296,358 | $ 1,114,372 |

Exploration expenses, including geological and geophysical expenses and delay rentals for unevaluated oil and gas properties are charged to expense as incurred. Exploratory drilling costs are initially capitalized as unproved property, not subject to depletion, but charged to expense if and when the well is determined not to have found proved oil and gas reserves.

The Company capitalized interest expense totaling \$1.7 million, \$2.3 million and \$1.1 million for the years ended December 31, 2018, 2017, and 2016, respectively.

*Other Property and Equipment*

Other property and equipment include land, buildings, leasehold improvements, vehicles, computer equipment and software, telecommunications equipment, and furniture and fixtures. These items are recorded at cost, or fair value if acquired through a business acquisition.

### *(e) Accounts Payable and Accrued Liabilities*

A summary of accounts payable is as follows (in thousands):

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Trade payables | $ 27,481 | $ 44,516 |
| Royalty payables | 70,019 | 17,483 |
| Production & ad valorem taxes | 1,811 | 967 |
| Derivative payable | 4,736 | 941 |
| Other payables | 12,688 | 12,267 |
| Total accounts payable | $ 116,735 | $ 76,174 |

A summary of accrued liabilities is as follows (in thousands):

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Ad valorem and production taxes | $ 6,193 | $ 4,299 |
| Employee compensation | 6,595 | 8,667 |
| Royalties | 39,969 | 9,660 |
| Short term derivatives | — | 14,875 |
| Other | 4,152 | 4,161 |
| Total accrued liabilities | $ 56,909 | $ 41,662 |

### *(f) Revenue Recognition*

*Product Revenue*

The Company's revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from the natural gas. Sales of natural gas, NGLs, and oil are recognized when the Company satisfies a performance obligation by transferring control of a product to a customer. Payment is generally received one month after the sale has occurred.

**Natural Gas**

Under the Company's natural gas sales contracts, the Company delivers natural gas to the purchaser at an agreed upon delivery point. Natural gas is transported from the wellhead to delivery points specified under sales contracts. To deliver natural gas to these points, the Company uses third parties to gather, compress, process and transport the natural gas. The Company maintains control of the natural gas during gathering, compression, processing, and transportation. The Company's sales contracts provide that it receive a specific index price adjusted for pricing differentials. The Company transfers control of the product at the delivery point and recognizes revenue based on the contract price. The costs to gather, compress, process and transport the natural gas are recorded as transportation, gathering and compression expense.

**NGLs**

The Company sells NGLs directly to the NGLs purchaser. For these NGLs, the sales contracts provide that the Company deliver the product to the purchaser at an agreed upon delivery point and that the Company receives a specific index price adjusted for pricing differentials. The Company transfers control of the product to the purchaser at the delivery point and recognizes revenue based on the contract price. The costs to further process and transport NGLs are recorded as transportation, gathering and compression expense.

**Oil**

Under the Company's oil sales contracts, the Company generally sells oil to the purchaser from storage tanks at central stabilization facilities and well pads and collects a contractually agreed upon index price, net of pricing differentials. The Company transfers control of the product from the central stabilization facilities and well pads to the purchaser and recognizes revenue based on the contract price.

*Marketing Revenue*

Brokered natural gas and marketing revenues are derived from activities to purchase and sell third-party natural gas and to market excess firm transportation capacity to third parties. The Company retains control of the purchased natural gas and NGLs prior to delivery to the purchaser. The Company has concluded that it is the principal in these arrangements and therefore the Company recognizes revenue on a gross basis, with costs to purchase and transport natural gas presented as brokered natural gas and marketing expense. Contracts to sell third party natural gas are generally subject to similar terms as contracts to sell the Company's produced natural gas and NGLs. The Company satisfies performance obligations to the purchaser by transferring control of the product at the delivery point and recognizes revenue based on the price received from the purchaser.

*Disaggregation of Revenue*

The following table illustrates the revenue disaggregated by type for the periods indicated:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| **Revenues (in thousands)** | | | |
| Natural gas sales | $ 274,239 | $ 241,379 | $ 134,618 |
| NGL sales | 86,152 | 64,109 | 38,204 |
| Oil sales | 138,202 | 74,690 | 50,193 |
| Brokered natural gas and marketing revenue | 16,552 | 3,481 | 12,019 |
| Total revenues | $ 515,145 | $ 383,659 | $ 235,034 |

*Transaction Price Allocated to Remaining Performance Obligations*

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient allowed in the revenue accounting standard that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligations are part of a contract that has an original expected duration of one year or less.

For any product sales that have a contract term greater than one year, the Company has also utilized the practical expedient that states that it is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these product sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. Currently, any product sales that have a contractual term greater than one year have no long-term fixed considerations.

*Contract Balances*

Under the Company's sales contracts, customers are invoiced once performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities. Accounts receivable attributable to the Company's revenue contracts with customers was $94.1 million and $52.9 million at December 31, 2018 and December 31, 2017, respectively.

***(g) Major Customers***

The Company sells production volumes to various purchasers. For the years ended December 31, 2018, 2017, and 2016, there were one, two and four customers, respectively, that accounted for 10% or more of the total natural gas, NGLs and oil sales. The following table sets forth the Company's major customers and associated percentage of revenue for the periods indicated:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| **Purchaser** | | | |
| Antero Resources | — | — | 14% |
| Concord Energy | — | — | 12% |
| Emera Energy Services | — | 17% | — |
| EnLink Midstream | — | — | 17% |
| Marathon Petroleum | 25% | 10% | — |
| Sequent Energy Management | — | — | 20% |
| Total | 25% | 27% | 63% |

Management believes that the loss of any one customer would not have a material adverse effect on the Company's ability to sell natural gas, NGLs and oil production because it believes that there are potential alternative purchasers although it may be necessary to establish relationships with new purchasers. However, there can be no assurance that the Company can establish such relationships or that those relationships will result in an increased number of purchasers.

***(h) Concentration of Credit Risk***

The following table summarizes concentration of receivables, net of allowances, by product or service as of December 31, 2018 and December 31, 2017 (in thousands):

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Receivables by product or service: | | |
| Sale of oil and natural gas and related products and services | $ 94,107 | $ 52,908 |
| Joint interest owners | 24,830 | 23,154 |
| Derivatives | 372 | 1,528 |
| Other | 23 | 19 |
| Total | $ 119,332 | $ 77,609 |

Oil and natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the State of Ohio. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, the Company exposes itself to the credit risk of counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. The fair value of the Company's commodity unsettled derivative contracts was a net asset position of $5.7 million and a net liability position of ($5.1) million at December 31, 2018 and 2017, respectively. Other than, as provided by the revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under the Company's contracts, nor are they required to provide credit support to the Company. As of December 31, 2018, the Company did not have past-due receivables from or payables to any of the counterparties.

***(i) Depreciation, Depletion and Amortization***

*Oil and Natural Gas Properties*

Depreciation, depletion, and amortization ("DD&A") of capitalized costs of proved oil and natural gas properties is computed using the unit-of-production method on a field level basis using total estimated proved reserves. The reserve base used to calculate DD&A for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate DD&A for drilling, completion and well equipment costs, which include development costs and successful exploration drilling costs, includes only proved developed reserves. DD&A expense relating to proved oil and natural gas properties for the years ended December 31, 2018, 2017, and 2016 totaled approximately $132.5 million, $116.8 million and $91.0 million, respectively.

*Other Property and Equipment*

Depreciation with respect to other property and equipment is calculated using straight-line methods based on expected lives of the individual assets or groups of assets ranging from 5 to 40 years. Depreciation for the years ended December 31, 2018, 2017, and 2016 totaled approximately $1.8 million, $2.0 million and $1.9 million, respectively. This amount is included in DD&A expense in the consolidated statements of operations.

***(j) Impairment of Long-Lived Assets***

The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

The review of the Company's oil and gas properties is done by determining if the historical cost of proved and unproved properties less the applicable accumulated DD&A and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Company's plans to continue to produce and develop proved reserves and a risk-adjusted portion of probable reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. The Company estimates prices based upon current contracts in place, adjusted for basis differentials and market-related information, including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets. As a result of the decline in commodity prices, the Company recognized impairment expenses of approximately $17.7 million for the year ended December 31, 2016 relating to proved properties in the Marcellus Shale.

The aforementioned impairment charges represented a significant Level 3 measurement in the fair value hierarchy. The primary input used was the Company's forecasted discount net cash flows.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the properties. An impairment charge is recorded if conditions indicate the Company will not explore the acreage prior to expiration of the applicable leases. The Company recorded impairment charges of unproved oil and gas properties related to lease expirations of $27.6 million, $28.3 million, and $29.8 million for the years ended December 31, 2018, 2017, and 2016, respectively. These costs are included in exploration expense in the consolidated statements of operations.

### *(k) Income Taxes*

The Company accounts for income taxes, as required, under the liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

ASC Topic 740 " Income Taxes " provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. Income tax positions must meet a more-likely-than-not recognition threshold at the effective date to be recognized upon the adoption of the uncertain tax position guidance and in subsequent periods. This interpretation also provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company has not recorded a reserve for any uncertain tax positions to date.

### *(l) Fair Value of Financial Instruments*

The Company has established a hierarchy to measure its financial instruments at fair value, which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The hierarchy defines three levels of inputs that may be used to measure fair value:

*Level 1* —Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

*Level 2* —Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market date for substantially the entire contractual term of the asset or liability. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

*Level 3* —Unobservable inputs that reflect the entity's own assumptions about the assumption market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

### *(m) Derivative Financial Instruments*

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of the energy commodities it sells.

Derivatives are recorded at fair value and are included on the consolidated balance sheets as current and noncurrent assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual expiration date. Derivatives with expiration dates within the next 12 months are classified as current. The Company netted the fair value of derivatives by counterparty in the accompanying consolidated balance sheets where the right to offset exists. The Company's derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities. Premiums for options are included in cash flows from operating activities.

The valuation of the Company's derivative financial instruments represents a Level 2 measurement in the fair value hierarchy.

### *(n) Asset Retirement Obligation*

The Company recognizes a legal liability for its asset retirement obligations ("ARO") in accordance with Topic ASC 410, "Asset Retirement and Environmental Obligations," associated with the retirement of a tangible long-lived asset, in the period in which it is incurred or becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The Company measures the fair value of its ARO using expected future cash outflows for abandonment discounted back to the date that the abandonment obligation was measured using an estimated credit adjusted rate, which was 10.33% for the years ended December 31, 2018 and 2017, respectively.

Estimating the future ARO requires management to make estimates and judgments based on historical estimates regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

The following table sets forth the changes in the Company's ARO liability for the periods indicated (in thousands):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Asset retirement obligations, beginning of period | $ 6,029 | $ 4,806 | $ 3,401 |
| Additional liabilities incurred | 418 | 679 | 1,014 |
| Accretion | 663 | 544 | 391 |
| Asset retirement obligations, end of period | $ 7,110 | $ 6,029 | $ 4,806 |

The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to ARO represent a significant nonrecurring Level 3 measurement.

### *(o) Lease Obligations*

The Company leases office space under an operating lease that expires in 2024. The lease terms begin on the date of initial possession of the leased property for purposes of recognizing lease expense on a straight-line basis over the term of the lease. The Company does not assume renewals in its determination of the lease terms unless the renewals are deemed to be reasonably assured at lease inception.

### *(p) Off-Balance Sheet Arrangements*

The Company does not have any off-balance sheet arrangements.

### *(q) Segment Reporting*

The Company operates in one industry segment: the oil and natural gas exploration and production industry in the United States. All of its operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

### *(r) Debt Issuance Costs*

The expenditures related to issuing debt are capitalized and reported as a reduction of the Company's debt balance in the accompanying balance sheets. These costs are amortized over the expected life of the related instruments using the effective interest rate method. When debt is retired before maturity or modifications significantly change the cash flows, related unamortized costs are expensed.

### *(s) Recent Accounting Pronouncements*

*Recently Adopted*

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)" ("Update 2014-09"), which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, "Property, Plant and Equipment", and intangible assets within the scope of Topic 350, "Intangibles—Goodwill and Other") are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The Company adopted this standard effective January 1, 2018 using the modified retrospective method. The Company did not recognize a significant impact on its financial position or results of operations. Upon adoption of this new standard, the Company did not record a cumulative effect adjustment nor did the Company alter its existing information technology and internal controls outside of ongoing contract review processes in order to identify the impact of future revenue contracts entered into by the Company. Additional disclosures have been included to provide further detail regarding the Company's revenue recognition policies.

In August 2016, the FASB issued ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments." The new standard provides guidance on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. These requirements are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted. The Company adopted this standard effective January 1, 2018 and did not recognize a significant impact on its financial position, results of operations, or statement of cash flows.

In January 2017, the FASB issued ASU 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business." Currently under the standard, there are three elements of a business: inputs, processes and outputs. The revised guidance adds an initial screen test to determine if substantially all of the fair value of the gross assets acquired is concentrated in a single asset or group of similar assets. If that screen is met, the set of assets is not a business. The new framework also specifies the minimum required inputs and processes necessary to be a business. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company adopted this standard effective January 1, 2018 and considered the new guidance in its assessment of the accounting treatment for the Flat Castle Acquisition. (See Note 3— *Acquisition*).

*Accounting Pronouncements Not Yet Adopted*

In February 2016, the FASB issued Update 2016-02, "Leases (Topic 842)", which increases transparency and comparability among organizations by recognizing right-of-use (ROU) lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Update 2016-02 maintains a distinction between finance leases and operating leases, which is substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous lease guidance. Retaining this distinction allows the recognition, measurement and presentation of expenses and cash flows arising from a lease to remain similar to the previous accounting treatment. A lessee is permitted to make an accounting policy election by class of underlying asset to exclude from balance sheet recognition any lease assets and lease liabilities with a term of 12 months or less, and instead to recognize lease expense on a straight-line basis over the lease term. For both financing and operating leases, the ROU asset and lease liability will be initially measured at the present value of the lease payments in the statement of financial position. For public business entities, the amendments in this update are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach with the option to adopt certain practical expedients. In July 2018, the FASB issued Update 2018-11 which provides entities with the option to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption.

The Company will adopt Topic 842 guidance as of January 1, 2019 using the transition method that allows a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Company has elected the transition relief package of practical expedients by applying previous accounting conclusions under ASC 840 to all of its leases that existed prior to the transition date. As a result, the Company will not reassess 1) whether existing or expired contracts contain leases 2) lease classification for any existing or expired leases and 3) whether lease origination costs qualified as initial direct costs. The Company will not elect the practical expedient to use hindsight in determining a lease term and impairment of ROU assets at the adoption date. Additionally, the Company will elect the short-term practical expedient for all of its asset classes by establishing an accounting policy to exclude leases with a term of 12 months or less. The Company will not separate lease components from non-lease components for its specified asset classes. Lastly, the Company will adopt the easement practical expedient which allows the Company to apply ASC 842 prospectively to land easements after the adoption date. Easements that existed or expired prior to the adoption date that were not previously assessed under ASC 840 will not be reassessed. The Company has implemented a third-party supported lease accounting system to account for the identified leases and is currently in the process of performing final testing of this system.

The adoption of Topic 842 will have a material impact on the Company’s Consolidated Balance Sheet due to the initial recognition of ROU assets and lease liabilities. In 2019, the Company expects to recognize a ROU asset and corresponding lease liability between $10 million to $15 million on its Consolidated Balance Sheet. Due to the BRMR Merger closing subsequent to the year ended December 31, 2018, the initial analysis in relation to BRMR’s adoption of Topic 842 is in process and will be accounted for in the period it closed.

***(t) Change in Estimates***

During the year ended December 31, 2016, the Company reduced its estimate of amounts due from a non-operated partner related to the sale of natural gas and NGLs, net of associated costs, based on revised information received from the non-operated partner during the period. As a result, the Company decreased accounts receivable by approximately $4 million, increased revenue from oil and natural gas sales by approximately $1.5 million, and increased transportation, gathering and compression expense by approximately $5.8 million, which increased the net loss for the year ended December 31, 2016 by approximately $4 million, or $0.02 per common share.

During the year ended December 31, 2016, the Company reduced its estimate for production and ad valorem tax expense based on recent historical experience and additional information received during the period. As a result, the Company decreased the accrual for production and ad valorem taxes to be paid by approximately $4 million, which decreased the net loss for the year ended December 31, 2016 by a corresponding amount, or $0.30 per common share.

***(u) Correction of Immaterial Error***

During the three months ended March 31, 2017, the Company determined that its estimated accrual for production and ad valorem tax expense was overstated for prior periods. The Company evaluated the materiality of this error on both a quantitative and qualitative basis under the guidance of ASC 250 “Accounting Changes and Errors Corrections,” and determined that it did not have a material impact to previously issued financial statements.

Although the error was immaterial to prior periods, the prior period financial statements were revised, in accordance with SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*, due to the significance of the out-of-period correction to the current period. Immaterial errors related to periods prior to the year ended December 31, 2016 are reflected as an adjustment to beginning accumulated deficit for that year. Periods not presented herein will be revised, as applicable, in future filings.

A reconciliation of the effects of the revision to amounts in the previously reported consolidated financial statements is as follows (in thousands, except per share amounts):

| | As of December 31, 2016 | | |
|---|---|---|---|
| | As Reported | Adjustment | As Adjusted |
| **Balance Sheet** | | | |
| Accounts receivable | $ 43,638 | $ 785 | $ 44,423 |
| Total current assets | 249,630 | 785 | 250,415 |
| Total assets | 1,197,859 | 785 | 1,198,644 |
| Accrued liabilities | 64,150 | (9,106) | 55,044 |
| Total current liabilities | 140,625 | (9,106) | 131,519 |
| Total liabilities | 651,143 | (9,106) | 642,037 |
| Accumulated deficit | (1,414,561) | 9,891 | (1,404,670) |
| Total stockholders' equity | 546,716 | 9,891 | 556,607 |
| Total liabilities and stockholders' equity | 1,197,859 | 785 | 1,198,644 |

| | As of December 31, 2016 | | |
|---|---|---|---|
| | As Reported | Adjustment | As Adjusted |
| **Statement of Stockholders' Equity** | | | |
| Accumulated deficit | $(1,414,561) | $ 9,891 | $(1,404,670) |
| Total stockholders' equity | 546,716 | 9,891 | 556,607 |

| | As of December 31, 2016 | | |
|---|---|---|---|
| | As Reported | Adjustment | As Adjusted |
| **Statement of Operations** | | | |
| Production and ad valorem taxes | $ 4,998 | $ 2,929 | $ 7,927 |
| Total operating expenses | 349,507 | 2,929 | 352,436 |
| Operating loss | (114,473) | (2,929) | (117,402) |
| Loss before income taxes | (203,260) | (2,929) | (206,189) |
| Net loss | (203,806) | (2,929) | (206,735) |
| Basic and diluted loss per share | $ (12.60) | $ (0.24) | $ (12.84) |

| | As of December 31, 2016 | | |
|---|---|---|---|
| | As Reported | Adjustment | As Adjusted |
| **Statement of Comprehensive Loss** | | | |
| Net loss | $ (203,806) | $ (2,929) | $ (206,735) |
| Total Comprehensive loss | (203,806) | (2,929) | (206,735) |

| | As of December 31, 2016 | | |
|---|---|---|---|
| | As Reported | Adjustment | As Adjusted |
| **Statement of Cash Flows** | | | |
| Net loss | $ (203,806) | $ (2,929) | $ (206,735) |
| Accounts receivable | (20,563) | (714) | (21,277) |
| Accounts payable and accrued liabilities | (2,849) | 3,643 | 794 |

## Note 3—Acquisition

***Eclipse Resources-PA, LP Acquisition***

On January 18, 2018, Eclipse Resources-PA, LP, a wholly owned subsidiary of the Company, completed its acquisition of certain oil and gas leases, one producing well and other oil and gas rights and interests covering approximately 44,500 net acres located in Tioga and Potter Counties, Pennsylvania from Travis Peak Resources, LLC for an aggregate adjusted purchase price of $90 million, which was paid entirely with approximately 2.5 million shares of the Company's common stock (the "Flat Castle Acquisition"). The transaction was accounted for as an asset acquisition. Approximately $86 million of the purchase price was allocated to unproved oil and natural gas properties and approximately $4 million was allocated to proved oil and gas properties associated with the producing well acquired. In addition, the Company capitalized approximately $1 million of transaction costs related to the acquisition.

During the year ended December 31, 2018, the Company assigned its option to purchase all of the outstanding equity interests of Cardinal NE Holdings, LLC ("Cardinal"), a wholly owned subsidiary of Cardinal Midstream II, LLC which owns midstream infrastructure with associated gathering rights on acreage in the Flat Castle area to a third party. The third party exercised its option of Cardinal in July 2018.

***Merger with Blue Ridge Mountain Resources***

On February 28, 2019, the Company completed its previously announced business combination transaction with Blue Ridge Mountain Resources, Inc. ("BRMR") pursuant to that certain Agreement and Plan of Merger, dated as of August 25, 2018 and amended as of January 7, 2019 (the "Merger Agreement"), by and among the Company, Everest Merger Sub Inc., a Delaware corporation and a wholly owned subsidiary of the Company ("Merger Sub"), and BRMR. Pursuant to the Merger Agreement, Merger Sub merged with and into BRMR with BRMR continuing as the surviving corporation and a wholly owned subsidiary of the Company (the "BRMR Merger").

As a result of the BRMR Merger, each share of common stock, par value $0.01 per share, of BRMR issued and outstanding immediately prior to the effective time of the BRMR Merger (the "Effective Time"), excluding certain Excluded Shares (as such term is defined in the Merger Agreement), was converted into the right to receive from the Company 0.29506 of a validly issued, fully-paid, and nonassessable share of common stock, par value $0.01 per share, of the Company. The exchange ratio reflects an adjustment to account for the 15-to-1 reverse stock (See Note 11— *Earnings (Loss) Per Share*). Former stockholders of BRMR will receive cash for any fractional shares of the Company's common stock to which they might otherwise be entitled as a result of the BRMR Merger. In addition, upon completion of the BRMR Merger, all shares of BRMR restricted stock and all BRMR restricted stock units and performance interest awards were converted into the right to receive shares of common stock of the Company or cash, in each case as specified in the Merger Agreement.

Due to the BRMR Merger closing subsequent to the year ended December 31, 2018, the initial accounting for the acquisition will be accounted for in the period it closed and the Company is in the process of determining the fair values of the net assets acquired.

## Note 4—Sale of Oil and Natural Gas Property Interests

*Asset Sales*

During the year ended December 31, 2016, the Company completed the sale of its Conventional oil and gas properties and related equipment for approximately $4.7 million. As of December 31, 2015, the Company was actively negotiating the sale of these assets and the costs related to these properties of approximately $21.8 million and corresponding asset retirement obligations of approximately $19.1 million were classified as held for sale in the consolidated balance sheets as of December 31, 2015. As a result of this sale, the Company recognized a gain of approximately $1.1 million.

During the year ended December 31, 2016, the Company sold additional pipeline assets, which resulted in proceeds of approximately $0.4 million and a loss of less than $0.1 million.

During the year ended December 31, 2016, the Company received $3.9 million from the sale of mineral interests related primarily to unproved properties to a third party. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and gas properties.

During the year ended December 31, 2016, the Company received $4.8 million from the sale of unproved leases to a third party. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and gas properties.

During the year ended December 31, 2016, the Company received approximately $63.8 million from a completed asset sale with a third party totaling approximately 9,900 acres. As a result of this sale, the Company recognized a loss of approximately $7.6 million.

During the year ended December 31, 2017, the Company received approximately $0.5 million from a completed asset sale with a third party totaling approximately 100 acres. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and natural gas properties.

During the year ended December 31, 2017, the Company received approximately $0.8 million from a completed asset sale with a third party totaling approximately 150 acres. As a result of this sale, the Company recognized a gain of approximately $0.2 million.

During the year ended December 31, 2018, the Company received approximately $6.0 million from a completed asset sale of approximately 1,000 acres to a third party. As a result of this sale, the Company recognized a gain of approximately $1.5 million.

During the year ended December 31, 2018, the Company received approximately $3.8 million from a completed asset sale of approximately 400 acres to a third party. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and natural gas properties.

During the year ended December 31, 2018, the Company received approximately $0.3 million from a completed asset sale of approximately 50 acres to a third party. As a result of this sale, the Company recognized a gain of approximately $0.3 million.

During the year ended December 31, 2018, the Company sold the $0.2 million of pipeline assets. As a result of this sale, the Company recognized a loss of less than approximately $0.1 million. These pipeline assets were classified as held for sale on the consolidated balance sheets as of December 31, 2015.

*Acreage Trades*

During the year ended December 31, 2016, the Company received approximately $1.6 million from completed acreage trades with various working interest owners totaling approximately 249.5 acres. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and gas properties.

**Note 5—Derivative Instruments**

*Commodity derivatives*

The Company is exposed to market risk from changes in energy commodity prices within its operations. The Company utilizes derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas and oil. The Company currently uses a mix of over-the-counter fixed price swaps, basis swaps and put options spreads and collars to manage its exposure to commodity price fluctuations. All of the Company’s derivative instruments are used for risk management purposes and none are held for trading or speculative purposes.

The Company is exposed to credit risk in the event of non-performance by counterparties. To mitigate this risk, the Company enters into derivative contracts only with counterparties that are rated “A” or higher by S&P or Moody’s. The creditworthiness of counterparties is subject to periodic review. As of December 31, 2018, the Company’s derivative instruments were with Bank of Montreal, KeyBank, N.A, Morgan Stanley, Capital One N.A., BP Energy Company and Goldman Sachs. The Company has not experienced any issues of non-performance by derivative counterparties. Below is a summary of the Company’s derivative instrument positions, as of December 31, 2018, for future production periods:

*Natural Gas Derivatives*

| Description | Volume (MMBtu/d) | Production Period | Weighted Average Price ($/MMBtu) | |
|---|---|---|---|---|
| **Natural Gas Swaps:** | | | | |
| | 30,000 | January 2019 – March 2019 | $ | 2.90 |
| | 90,000 | January 2019 – December 2019 | $ | 2.84 |
| **Natural Gas Collars:** | | | | |
| Ceiling sold price (call) | 30,000 | October 2019 – December 2019 | $ | 2.95 |
| Floor sold price (put) | 30,000 | October 2019 – December 2019 | $ | 2.65 |
| **Natural Gas Three-way Collars:** | | | | |
| Floor purchase price (put) | 30,000 | January 2019 – March 2019 | $ | 3.00 |
| Ceiling sold price (call) | 30,000 | January 2019 – March 2019 | $ | 3.40 |
| Floor sold price (put) | 30,000 | January 2019 – March 2019 | $ | 2.50 |
| Floor purchase price (put) | 77,500 | January 2019 – December 2019 | $ | 2.72 |
| Ceiling sold price (call) | 77,500 | January 2019 – December 2019 | $ | 3.04 |
| Floor sold price (put) | 77,500 | January 2019 – December 2019 | $ | 2.30 |
| Floor purchase price (put) | 50,000 | January 2020 – June 2020 | $ | 2.70 |
| Ceiling sold price (call) | 50,000 | January 2020 – June 2020 | $ | 2.95 |
| Floor sold price (put) | 50,000 | January 2020 – June 2020 | $ | 2.25 |
| **Natural Gas Call/Put Options:** | | | | |
| Call sold | 30,000 | January 2019 – March 2019 | $ | 3.50 |
| Call sold | 30,000 | April 2019 – December 2019 | $ | 3.00 |
| Call sold | 10,000 | January 2019 – December 2019 | $ | 4.75 |
| **Basis Swaps:** | | | | |
| Appalachia - Dominion | 12,500 | April 2019 – October 2019 | $ | (0.52) |
| Appalachia - Dominion | 12,500 | April 2020 – October 2020 | $ | (0.52) |
| Appalachia - Dominion | 20,000 | January 2020 – December 2020 | $ | (0.59) |

*Oil Derivatives*

| Description | Volume (Bbls/d) | Production Period | Weighted Average Price ($/Bbl) | |
|---|---|---|---|---|
| **Oil Swaps:** | | | | |
| | 1,000 | January 2019 – March 2019 | $ | 61.00 |
| **Oil Three-way Collars:** | | | | |
| Floor purchase price (put) | 2,000 | January 2019 – December 2019 | $ | 50.00 |
| Ceiling sold price (call) | 2,000 | January 2019 – December 2019 | $ | 60.56 |
| Floor sold price (put) | 2,000 | January 2019 – December 2019 | $ | 40.00 |
| Floor purchase price (put) | 2,000 | January 2020 – June 2020 | $ | 62.50 |
| Ceiling sold price (call) | 2,000 | January 2020 – June 2020 | $ | 74.00 |
| Floor sold price (put) | 2,000 | January 2020 – June 2020 | $ | 55.00 |

*Fair values and gains (losses)*

The following table summarizes the fair value of the Company's derivative instruments on a gross basis and on a net basis as presented in the consolidated balance sheets (in thousands). None of the derivative instruments are designated as hedges for accounting purposes.

| As of December 31, 2018 | Gross Amount | Netting Adjustments(a) | Net Amount Presented in Balance Sheets | Balance Sheet Location |
|---|---|---|---|---|
| **Assets** | | | | |
| Commodity derivatives - current | $ 4,960 | $ (845) | $ 4,115 | Other current assets |
| Commodity derivatives - noncurrent | 1,910 | — | 1,910 | Other assets |
| **Total assets** | $ 6,870 | $ (845) | $ 6,025 | |
| **Liabilities** | | | | |
| Commodity derivatives - current | $ (845) | $ 845 | $ — | Accrued liabilities |
| Commodity derivatives - noncurrent | (326) | — | (326) | Other liabilities |
| **Total liabilities** | $ (1,171) | $ 845 | $ (326) | |

| As of December 31, 2017 | Gross Amount | Netting Adjustments(a) | Net Amount Presented in Balance Sheets | Balance Sheet Location |
|---|---|---|---|---|
| **Assets** | | | | |
| Commodity derivatives - current | $ 15,971 | $ (6,380) | $ 9,591 | Other current assets |
| Commodity derivatives - noncurrent | 469 | (176) | 293 | Other assets |
| **Total assets** | $ 16,440 | $ (6,556) | $ 9,884 | |
| **Liabilities** | | | | |
| Commodity derivatives - current | $ (21,256) | $ 6,380 | $ (14,876) | Accrued liabilities |
| Commodity derivatives - noncurrent | (252) | 176 | (76) | Other liabilities |
| **Total liabilities** | $ (21,508) | $ 6,556 | $ (14,952) | |

(a) The Company has agreements in place that allow for the financial right to offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.

The following table presents the Company's reported gains and losses on derivative instruments and where such values are recorded in the consolidated statements of operations for the periods presented (in thousands):

| | Location of Gain (Loss) | For the Year Ended December 31, 2018 | 2017 | 2016 |
|---|---|---|---|---|
| Commodity derivatives | Gain (loss) on derivative instruments | $ (21,169) | $ 45,365 | $ (52,338) |

## Note 6—Fair Value Measurements

***Fair Value Measurement on a Recurring Basis***

The following table presents, by level within the fair value hierarchy, the Company's assets and liabilities that are measured at fair value on a recurring basis. The carrying amounts reported in the consolidated balance sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

The fair value of the Company's derivatives is based on third-party pricing models, which utilize inputs that are readily available in the public market, such as natural gas forward curves. These values are compared to the values given by counterparties for reasonableness. Since natural gas swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2.

| | Level 1 | Level 2 | Level 3 | Total Fair Value |
|---|---|---|---|---|
| As of December 31, 2018: (in thousands) | | | | |
| Commodity derivative instruments | $ — | $ 5,699 | $ — | $ 5,699 |
| Total | $ — | $ 5,699 | $ — | $ 5,699 |
| As of December 31, 2017: (in thousands) | | | | |
| Commodity derivative instruments | $ — | $ (5,068) | $ — | $ (5,068) |
| Total | $ — | $ (5,068) | $ — | $ (5,068) |

***Nonfinancial Assets and Liabilities***

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and natural gas property acquired include the Company's estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. Additionally, fair value is used to determine the inception value of the Company's AROs. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to the Company's ARO represent a nonrecurring Level 3 measurement. (See Note 2(n)).

The Company reviews its proved oil and natural gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. As such, the fair value of oil and natural gas properties used in estimating impairment represents a nonrecurring Level 3 measurement. (See Note 2(l)).

The estimated fair values of the Company's financial instruments closely approximate the carrying amounts due, except for long-term debt. (See Note 7— *Debt*)

**Note 7—Debt**

***8.875% Senior Unsecured Notes Due 2023***

On July 6, 2015, the Company issued $550 million in aggregate principal amount of 8.875% Senior Unsecured Notes due 2023 at an issue price of 97.903% of principal amount of the notes, plus accrued and unpaid interest, if any, to Deutsche Bank Securities Inc. and other initial purchasers. In this private offering, the senior unsecured notes were sold for cash to qualified institutional buyers in the United States pursuant to Rule 144A of the Securities Act and to persons outside of the United States in compliance with Rule S under the Securities Act. Upon closing, the Company received proceeds of approximately $525.5 million, after deducting original issue discount, the initial purchasers discounts and offering expenses, of which the Company used approximately $510.7 million to finance the redemption of all of its outstanding 12.0% Senior PIK notes. The Company used the remaining proceeds to fund its capital expenditure plan and for general corporate purposes.

During the years ended December 31, 2018, 2017, and 2016, the Company amortized $3.6 million, $3.4 million and $3.3 million, respectively, of deferred financing costs and debt discount to interest expense using the effective interest method.

The indenture governing the senior unsecured notes contains covenants that, among other things, limit the ability of the Company and its restricted subsidiaries to: (i) incur additional indebtedness, (ii) pay dividends on capital stock or redeem, repurchase or retire the Company's capital stock or subordinated indebtedness, (iii) transfer or sell assets, (iv) make investments, (v) create certain liens, (vi) enter into agreements that restrict dividends or other payments to the Company from its restricted subsidiaries, (vii) consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries, taken as a whole, (viii) engage in transactions with affiliates, and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the indenture. In addition, if the senior unsecured notes achieve an investment grade rating from either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services, and no default under the indenture has then occurred and is continuing, many of such covenants will be suspended. The indenture also contains events of default, which include, among others and subject in certain cases to grace and cure periods, nonpayment of principal or interest, failure by the Company to comply with its other obligations under the indenture, payment defaults and accelerations with respect to certain other indebtedness of the Company and its restricted subsidiaries, failure of any guarantee on the senior unsecured notes to be enforceable, and certain events of bankruptcy or insolvency. The Company was in compliance with all applicable covenants in the indenture at December 31, 2018.

During the year ended December 31, 2016, the Company repurchased $39.5 million of the outstanding senior unsecured notes in open market purchases for $23.4 million. The principal of the outstanding senior unsecured notes that were repurchased less cash proceeds and unamortized debt discount and deferred financing costs were charged to gain on early extinguishment of debt, totaling $14.5 million for the year ended December 31, 2016. The Company repurchased all such senior unsecured notes with cash on hand.

Based on Level 2 market data inputs, the fair value of the senior unsecured notes at December 31, 2018 was approximately $437.9 million.

***Revolving Credit Facility***

During the first quarter of 2014, the Company entered into a $500 million senior secured revolving bank credit facility (the "revolving credit facility") that was scheduled to mature in 2018. Borrowings under the revolving credit facility are subject to borrowing base limitations based on the collateral value of the Company's proved properties and commodity hedge positions and are subject to semiannual redeterminations (April and October).

The revolving credit facility was amended and restated on January 12, 2015. The primary change effected by the Amendment was to add Montage Resources Corporation as a party to the revolving credit facility and thereby subject the Company to the representations, warranties, covenants and events of default provisions thereof. Relative to the Eclipse I's previous credit agreement, the Credit Agreement also (i) requires financial reporting regarding, and tests financial covenants with respect to, Montage Resources Corporation rather than Eclipse I, (ii) increases the basket sizes under certain of the negative covenants, and (iii) includes certain other changes favorable to Eclipse I. Other terms of the Credit Agreement remain generally consistent with Eclipse I's previous credit agreement.

On February 24, 2016, the Company amended its revolving credit facility to, among other things, adjust the quarterly minimum interest coverage ratio, which is the ratio of EBITDAX to Cash Interest Expense, and to permit the sale of certain conventional properties. The amendment to the revolving credit facility also increased the Applicable Margin (as defined in the Credit Agreement) applicable to loans and letter of credit participation fees under the Credit Agreement by 0.5% and required the Company to, within 60 days of the effectiveness of the amendment, execute and deliver additional mortgages on the oil and gas properties that include at least 90% of the proved reserves.

On February 24, 2017, the Company entered into an additional amendment that increased the borrowing base from $125 million to $175 million, while extending the maturity of the revolving credit facility to February 2020. In addition, the amendment modified the minimum interest coverage ratio covenant to a net leverage covenant of Net Debt to EBITDAX. On August 1, 2017, the Company entered into an additional amendment that increased the borrowing base from $175 million to $225 million.

At December 31, 2018, the borrowing base was $225 million and the Company had $32.5 million in outstanding borrowings. After giving effect to outstanding letters of credit issued by the Company totaling $27.0 million, the Company had available borrowing capacity under the revolving credit facility of $165.5 million.

On February 28, 2019, the Company amended and restated the credit agreement governing its revolving credit facility to, among other things, increase the borrowing base from $225 million to $375 million and extend the maturity date thereof to approximately five years after the closing of the BRMR Merger. The amended and restated credit agreement also adjusted the ratio of Consolidated Total Funded Net Debt to EBITDAX (as such terms are defined in the amended and restated credit agreement) to provide that the Company will not, as of the last day of any fiscal quarter (commencing with the fiscal quarter ending March 31, 2019), permit its ratio of Consolidated Total Funded Net Debt to EBITDAX for the four previous fiscal quarters to be greater than 4.00 to 1.00.

Subsequent to December 31, 2018, the Company reduced its outstanding letters of credit to approximately $13.5 million. Further, the Company borrowed an incremental $85 million under its revolving credit facility, which reduced the available borrowing capacity to $244 million.

The revolving credit facility is secured by mortgages on 85% of the value of the Company's properties and guarantees from the Company's operating subsidiaries. The revolving credit facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and leverage coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate based on the Company's election at the time of borrowing. The Company was in compliance with all applicable covenants under the revolving credit facility as of December 31, 2018. Commitment fees on the unused portion of the revolving credit facility are due quarterly at 0.375%-0.500% of the unused facility based on utilization.

**Note 8—Benefit Plans**

*Defined Contribution Plan*

The Company currently maintains a retirement plan intended to provide benefits under section 401(K) of the Internal Revenue Code, under which employees are allowed to contribute portions of their compensation to a tax-qualified retirement account. Under the 401(K) plan, the Company provides matching contributions equal to 100% of the first 6% of employees' eligible compensation contributed to the plan. The Company recorded compensation expense of $0.9 million, $0.7 million and $0.7 million related to matching contributions, classified under general and administrative in the consolidated statements of operations, for the years ended December 31, 2018, 2017, and 2016, respectively.

**Note 9—Stock-Based Compensation**

The Company is authorized to grant up to 25,000,000 shares of common stock under its 2014 Long-Term Incentive Plan (as amended, the “Plan”). The Plan allows stock-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent rights, qualified performance-based awards and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of the Company’s Board of Directors. A total of 7,145,866 shares are available for future grant under the Plan as of December 31, 2018. The foregoing share numbers provided as of December 31, 2018 do not reflect any adjustment with respect to the 15-to-1 reverse stock split that occurred on February 28, 2019.

Our stock based compensation expense is as follows for the years ended December 31, 2018, 2017, and 2016 (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Restricted stock units | $ 4,014 | $ 5,301 | $ 4,006 |
| Performance units | 3,497 | 3,622 | 1,922 |
| Restricted stock issued to directors | 380 | 378 | 556 |
| Incentive units | — | — | (268) |
| Total expense | $ 7,891 | $ 9,301 | $ 6,216 |

*Restricted Stock Units*

Restricted stock unit awards vest subject to the satisfaction of service requirements. The Company recognizes expense related to restricted stock and restricted stock unit awards on a straight-line basis over the requisite service period, which is three years. The grant date fair values of these awards are determined based on the closing price of the Company’s common stock on the date of the grant. As of December 31, 2018, there was $4.0 million of total unrecognized compensation cost related to restricted stock units. The weighted average period for the shares to vest is approximately 1 year.

A summary of employee restricted stock unit awards activity during the year ended December 31, 2018 is as follows:

| | Number of shares | Weighted average grant date fair value | Aggregate intrinsic value (in thousands) |
|---|---|---|---|
| Total awarded and unvested, December 31, 2017 | 270,490 | $ 37.20 | $ 9,738 |
| Granted | 99,901 | 25.50 | |
| Vested | (132,406) | 42.42 | |
| Forfeited | (4,025) | 31.30 | |
| Total awarded and unvested, December 31, 2018 | 233,960 | $ 29.27 | $ 3,685 |

*Performance Units*

Performance unit awards vest subject to the satisfaction of a three-year service requirement and based on Total Shareholder Return ("TSR"), as compared to an industry peer group over that same period. The performance unit awards are measured at the grant date at fair value using a Monte Carlo valuation method. As of December 31, 2018, there was $3.5 million of total unrecognized compensation cost related to performance units. The weighted average period for the shares to vest is approximately 1 years.

A summary of performance stock unit awards activity during the year ended December 31, 2018 is as follows:

| | Number of shares | Weighted average grant date fair value | Aggregate intrinsic value (in thousands) |
|---|---|---|---|
| Total awarded and unvested, December 31, 2017 | 264,425 | $ 27.30 | $ 11,257 |
| Granted | 99,901 | 28.80 | |
| Vested | (11,536) | 27.51 | |
| Forfeited | (6,201) | 27.61 | |
| Total awarded and unvested, December 31, 2018 | 346,589 | $ 27.68 | $ 716 |

The determination of the fair value of the performance unit awards noted above uses significant Level 3 assumptions in the fair value hierarchy including an estimate of the timing of forfeitures, the risk free rate and a volatility estimate tied to the Company's public peer group. The following table presents the assumptions used to determine the fair value for performance stock units granted during the years ended December 31, 2018, 2017, and 2016:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Volatility | 89.70% | 50.41% | 49.84% |
| Risk-free interest rate | 2.37% | 1.34% | 0.96% |

The fair value of the performance stock units vested during the year ended December 31, 2017 was approximately $0.8 million.

*Restricted Stock Issued to Directors*

On May 11, 2015, the Company issued an aggregate of 8,833 restricted shares of common stock to its seven non-employee members of its Board of Directors, which became fully vested on May 11, 2016. For the year ended December 31, 2016, the Company recognized expense of approximately $0.3 million related to these awards.

On May 18, 2016, the Company issued an aggregate of 9,963 restricted shares of common stock to its three non-employee members of its Board of Directors that are not affiliated with the Company's controlling stockholder, which became fully vested on May 18, 2017. For the years ended December 31, 2017 and 2016, the Company recognized expense of approximately $0.2 million and $0.3 million, respectively, related to these awards.

On May 17, 2017, the Company issued an aggregate of 10,212 restricted shares of common stock to its three non-employee members of its Board of Directors that are not affiliated with the Company's controlling stockholder, which became fully vested on May 17, 2018. For the years ended December 31, 2017 and 2018, the Company recognized expense of approximately $0.2 million and $0.1 million, respectively, related to these awards.

On May 16, 2018, the Company issued an aggregate of 15,476 restricted shares of common stock to its three non-employee members of its Board of Directors that are not affiliated with the Company's controlling stockholder, which are scheduled to fully vest on May 16, 2019. For the year ended December 31, 2018, the Company recognized expense of approximately $0.3 million related to these awards. As of December 31, 2018, there was approximately $0.1 million of total unrecognized compensation cost related to outstanding restricted stock issued to the Company's Directors.

## Note 10—Equity

*Public Offering of Common Stock*

On June 28, 2016, the Company commenced an underwritten public offering of 2,500,000 shares of common stock, which was priced at $52.50 per share. The Company closed the offering on July 5, 2016 and received net proceeds of approximately $123.8 million (after deducting underwriting discounts and commissions and estimated expenses), which the Company used to fund its capital expenditure plan and for general corporate purposes.

## Note 11—Earnings (Loss) Per Share

*Earnings (Loss) Per Share*

Basic earnings (loss) per share ("EPS") is computed by dividing net income (loss) by the weighted-average number of shares of common stock outstanding during the period. Diluted EPS takes into account the dilutive effect of potential common stock that could be issued by the Company in conjunction with any stock awards that have been granted to directors and employees. In accordance with FASB ASC Topic 260, awards of non-vested shares shall be considered to be outstanding as of the grant date for purposes of computing diluted EPS even though their exercise is contingent upon vesting. During periods in which the Company incurs a net loss, diluted weighted-average shares outstanding are equal to basic weighted-average shares outstanding because the effect of all equity awards is antidilutive.

*Reverse Stock Split*

Effective immediately prior to the Effective Time on February 28, 2019 (See Note 3— *Acquisition*), the Company effected a 15-to-1 reverse stock split of its common stock. Holders of shares of the Company's common stock immediately prior to the Effective Time will receive cash for any fractional shares of the Company's common stock to which they might otherwise be entitled as a result of the reverse stock split. The reverse stock split lowered the par value to reflect the reduced shares with the offset to additional paid-in-capital. The below table retroactively reflects, in accordance with ASC 505 "Equity", the stock split that occurred after the year ended December 31, 2018 for the years ended December 31, 2018, 2017, and 2016, respectively:

| | Year Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| (in thousands, except per share data) | 2018 | | | 2017 | | | 2016 | | |
| | Income (Loss) | Shares | Per Share | Income (Loss) | Shares | Per Share | Income (Loss) | Shares | Per Share |
| **Basic:** | | | | | | | | | |
| Net income (loss), shares, basic | $18,826 | 19,999 | $ 0.94 | $8,525 | 17,479 | $ 0.49 | $(206,735) | 16,096 | $(12.84) |
| **Weighted-average number of shares of common stock-diluted:** | | | | | | | | | |
| Restricted stock and performance unit awards | — | 88 | | — | 200 | | — | — | |
| **Diluted:** | | | | | | | | | |
| Net income (loss), shares, diluted | $18,826 | 20,087 | $ 0.94 | $8,525 | 17,679 | $ 0.48 | $(206,735) | 16,096 | $(12.84) |

## Note 12—Related Party Transactions

During the years ended December 31, 2018, 2017, and 2016, the Company incurred approximately $0.6 million, respectively, related to flight charter services provided by BWH Air, LLC and BWH Air II, LLC, which are owned by the Company's former Chairman, President and Chief Executive Officer. The fees are paid in accordance with a standard service contract that does not obligate the Company to any minimum terms.

Travis Peak Resources, LLC, the seller from whom the Company acquired assets in the Flat Castle Acquisition, is an affiliate of EnCap Investments L.P. ("EnCap"). EnCap has representatives on the Board, and affiliates of EnCap collectively beneficially own a majority of the outstanding shares of the Company's common stock. (See Note 3— *Acquisition*).

## Note 13—Commitments and Contingencies

### *(a) Legal Matters*

From time to time, the Company may be a party to legal proceedings arising in the ordinary course of business. Management does not believe that a material loss is probable as a result of such proceedings.

### *(b) Environmental Matters*

The Company is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of the Company could be adversely affected.

### *(c) Leases*

The development of the Company's oil and natural gas properties under their related leases will require a significant amount of capital. The timing of those expenditures will be determined by the lease provisions, the term of the lease and other factors associated with unproved leasehold acreage. To the extent that the Company is not the operator of oil and natural gas properties that it owns an interest in, the timing, and to some degree the amount, of capital expenditures will be controlled by the operator of such properties.

The Company leases office space under an operating lease that expires in 2024. Rent expense related to lease agreements for the years ended December 31, 2018, 2017, and 2016 was $0.6 million, $0.6 million and $0.9 million, respectively.

The following is a schedule by year, of the future minimum lease payments required under the lease agreements as of December 31, 2018 (in thousands).

| | |
|---|---|
| 2019 | 1,360 |
| 2020 | 1,060 |
| 2021 | 929 |
| 2022 | 755 |
| 2023 | 755 |
| Thereafter | 1,619 |
| Total minimum lease payments | $ 6,478 |

*(d) Other Commitments (in thousands)*

| | Drilling rig commitments(i) | Firm transportation(ii) | Gas processing, gathering, and compression services(iii) | Total |
|---|---|---|---|---|
| Year Ending December 31: | | | | |
| 2019 | $ 1,287 | $ 80,083 | $ 26,271 | $ 107,641 |
| 2020 | — | 80,303 | 22,886 | 103,189 |
| 2021 | — | 80,083 | 18,147 | 98,230 |
| 2022 | — | 80,083 | 20,440 | 100,523 |
| 2023 | — | 80,083 | 18,515 | 98,598 |
| Thereafter | — | 700,549 | 61,923 | 762,472 |
| **Total** | $ 1,287 | $ 1,101,184 | $ 168,182 | $ 1,270,653 |

**(i)** **Drilling rig commitments -**The Company had contracts for the service of two rigs, which have both expired and the Company has entered into well-to-well contracts. The values in the table represent the gross amounts that the Company is committed to pay and does not deduct amounts that other parties are responsible for as a result of cost sharing arrangements with working interest partners. The Company will record in its consolidated financial statements the Company's proportionate share of costs based on its working interest, as applicable.

**(ii)** **Firm transportation -**The Company has entered into firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit the Company to transport minimum daily natural gas volumes at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. The amounts in this table represent the minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that the Company is committed to pay and does not deduct amounts that other parties are responsible for as a result of cost sharing arrangements with working interest partners. The Company will record in its consolidated financial statements the Company's proportionate share of costs based on its working interest.

**(iii)** **Gas processing, gathering, and compression services -**Contractual commitments for gas processing, gathering and compression service agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression agreements. The values in the table represent the gross amounts that the Company is committed to pay and does not deduct amounts that other parties are responsible for as a result of cost sharing arrangements with working interest partners. The Company will record in its consolidated financial statements its proportionate share of costs based on the Company's working interest.

## Note 14—Income Tax

For the year ended December 31, 2018, the Company's annual effective tax rate is approximately 0.0%. Despite reporting pre-tax book income of $18.8 million, the Company incurred a tax loss in the current year (due principally to intangible drilling cost amortization) and thus, no current federal income taxes will be due. This tax loss results in a net operating loss carryforward at December 31, 2018 in the amount of $667 million. Management assessed the realizability of the Company's deferred tax assets based on the more likely than not standard. Management considered several factors such as: (i) the Company's short (five-year) tax history, (ii) the lack of carryback potential resulting in a tax refund, and (iii) in light of current commodity pricing uncertainty, there is insufficient external evidence to suggest that net federal tax attribute carryforwards are realizable. As such, the Company has provided a valuation allowance of $208 million as of December 31, 2018.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Current | | | |
| Federal | $ — | $ — | $ — |
| State | — | — | 6 |
| Total current | — | — | 6 |
| Deferred | | | |
| Federal | — | — | — |
| State | — | — | 540 |
| Total deferred | — | — | 540 |
| Total income tax expense (benefit) | $ — | $ — | $ 546 |

The Company's income tax expense differs from the amount derived by applying the statutory federal rate to pretax loss principally due the effect of the following items (in thousands):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Income (loss) before income taxes | $ 18,826 | $ 8,525 | $ (206,189) |
| Statutory rate | 21% | 35% | 35% |
| Income tax benefit computed at statutory rate | 3,953 | 2,984 | (72,166) |
| Reconciling items: | | | |
| State income taxes | — | — | 546 |
| Other, net | 54 | 50 | 854 |
| Share-based compensation | 1,201 | (576) | — |
| Executive compensation limitation | 268 | 496 | — |
| Change in valuation allowance | (5,476) | (145,449) | 71,312 |
| Change in Federal tax rate | — | 142,495 | — |
| Income tax expense (benefit) | $ — | $ — | $ 546 |

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the Company's deferred taxes are detailed in the table below (in thousands):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Deferred tax asset: | | | |
| Oil and gas properties and equipment | $ 62,616 | $ 93,854 | $ 193,095 |
| Federal tax loss carryforwards | 140,059 | 114,652 | 145,628 |
| Derivative instruments and other | — | 1,064 | 16,829 |
| State effect of deferreds | — | — | — |
| Other, net | 7,398 | 4,639 | 4,259 |
| Deferred tax asset | 210,073 | 214,209 | 359,811 |
| Valuation allowance | (208,324) | (213,800) | (359,098) |
| Net deferred tax assets | $ 1,749 | $ 409 | $ 713 |
| Deferred tax liability: | | | |
| Derivative instruments and other | $ 1,197 | $ — | $ — |
| Other, net | 552 | 409 | 713 |
| Net deferred tax liability | $ 1,749 | $ 409 | $ 713 |
| Reflected in the accompanying consolidated balance sheet as: | | | |
| Net deferred tax asset | $ — | $ — | $ — |
| Net deferred tax liability | $ — | $ — | $ — |

The Company has U.S. federal tax loss carryforwards ("NOL") of approximately $667 million as of December 31, 2018. The NOL carryforwards will begin to expire in 2034. The tax years ended December 31, 2015 through 2018 will remain open to examination under the applicable statute of limitations in the U.S. and other jurisdictions in which the Company and its subsidiaries file income tax returns. However, the statute of limitations for examination of NOLs and other similar attribute carryforwards does not commence until the year the attribute is utilized. In some instances, state statutes of limitations are longer than those under U.S. federal tax law.

As of December 31, 2018, 2017, and 2016 the Company has not recorded a reserve for any uncertain tax positions. No federal income tax payments are expected in the upcoming four quarterly reporting periods.

As a result of the BRMR Merger (See Note 3— *Acquisition*), the Company may undergo an ownership change as described in Code section 382. This may limit the future annual availability of use of the Company's NOLs that accrued prior to the ownership change date as well as future tax depreciation, depletion and amortization amounts. The Company is still evaluating the impacts that Code section 382 will have on their tax attributes.

**Note 15—Subsidiary Guarantors**

Each subsidiary of the Company that guarantees the Company's revolving credit facility is required to fully and unconditionally, joint and severally, guarantee the Company's 8.875% Senior Unsecured Notes. Each such subsidiary of the Company in existence immediately prior to the BRMR Merger guaranteed the Company's 8.875% Senior Unsecured Notes. As a result of the BRMR Merger, and within the timeframe required by the indenture governing the Company's 8.875% Senior Unsecured Notes, the Company expects to cause BRMR and each of its subsidiaries that guarantees the Company's revolving credit facility to guarantee the Company's 8.875% Senior Unsecured Notes (See Note 7— *Debt* ). The Parent company has no independent assets or operations. The Company's wholly owned subsidiaries are not restricted from transferring funds to the Parent or other wholly owned subsidiaries. The Company's wholly owned subsidiaries do not have any restricted net assets.

A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person by way of merger, consolidation, or otherwise; or
- if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture.

**Note 16—Subsequent Events**

Management has evaluated subsequent events and believes that there are no events that would have a material impact on the aforementioned financial statements and related disclosures, except for analysis on Topic 842 related to the BRMR Merger (See Note 2— *Summary of Significant Accounting Policies*), the BRMR Merger (See Note 3— *Acquisition*), the amendment to the revolving credit facility (See Note 7— *Debt*), and the reverse stock split (See Note 11— *Earnings (Loss) Per Share*).

**Note 17—Quarterly Financial Information (unaudited)**

Summarized quarterly financial data for the years ended December 31, 2018 and 2017 are presented in the following table to retroactively reflect the 15-to-1 reverse stock split at the close the BRMR Merger. In the following table, the sum of basic and diluted "Income (loss) per common share" for the four quarters may differ from the annual amounts due to the required method of computing weighted average number of shares in the respective periods. Additionally, due to the effect of rounding, the sum of the individual quarterly loss per share amounts may not equal the calculated year loss per share amount (in thousands, except per share data).

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| Year ended December 31, 2018 | | | | |
| Total operating revenues | $ 110,192 | $ 103,622 | $ 130,123 | $ 171,208 |
| Total operating expenses | 95,651 | 92,989 | 108,929 | 123,590 |
| Operating income (loss) | 14,541 | 10,633 | 21,194 | 47,618 |
| Net income (loss) | (2,626) | (19,036) | 3,998 | 36,490 |
| Income (loss) per common share: | | | | |
| Basic | $ (0.13) | $ (0.95) | $ 0.20 | $ 1.81 |
| Diluted | $ (0.13) | $ (0.95) | $ 0.20 | $ 1.80 |

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| Year ended December 31, 2017 | | | | |
| Total operating revenues | $ 101,863 | $ 86,191 | $ 91,549 | $ 104,056 |
| Total operating expenses | 87,632 | 80,589 | 94,338 | 108,431 |
| Operating loss | 14,231 | 5,602 | (2,789) | (4,375) |
| Net income (loss) | 26,847 | 11,494 | (16,694) | (13,122) |
| Income (loss) per common share: | | | | |
| Basic | $ 1.54 | $ 0.66 | $ (0.95) | $ (0.75) |
| Diluted | $ 1.52 | $ 0.65 | $ (0.95) | $ (0.74) |

## Note 18—Supplemental Oil and Natural Gas Information (unaudited)

### *(a) Capitalized Costs*

A summary of the Company's capitalized costs are contained in the table below (in thousands):

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Oil and natural gas properties: | | |
| Unproved properties | $ 482,475 | $ 459,549 |
| Proved properties | 2,188,233 | 1,896,081 |
| Total oil and natural gas properties | 2,670,708 | 2,355,630 |
| Less accumulated depreciation, depletion and amortization | (1,380,650) | (1,248,200) |
| Net oil and natural gas properties | $ 1,290,058 | $ 1,107,430 |

### *(b) Costs Incurred in Oil and Natural Gas Property Acquisition and Development Activities*

A summary of the Company's cost incurred in oil and natural gas property acquisition and development activities is set forth below (in thousands):

| | December 31, 2018 | 2017 | 2016 |
|---|---|---|---|
| Acquisition costs: | | | |
| Unproved properties | $ 107,862 | $ 57,498 | $ 24,764 |
| Proved properties | 4,072 | — | — |
| Development cost | 239,467 | 257,119 | 150,778 |
| Exploration cost | 20,957 | 18,791 | 20,127 |
| Total acquisition, development and exploration costs | $ 372,358 | $ 333,408 | $ 195,669 |

### *(c) Reserve Quantity Information*

The following information represents estimates of the Company's proved reserves as of December 31, 2018 and December 31, 2017, which have been prepared and presented under SEC rules. These rules require companies to prepare their reserve estimates using specified reserve definitions and pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The pricing that was used for estimates of the Company's reserves as of December 31, 2018, 2017, and 2016 was based on an unweighted average 12-month average West Texas Intermediate posted price per Bbl for oil and NGLs and a Henry Hub spot natural gas price per MMBtu for natural gas.

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement may limit the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Appalachian Basin of Ohio and Pennsylvania. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The Company's proved oil and natural gas reserves are all located in the United States, within the States of Ohio and Pennsylvania. All of the estimates of the proved reserves at December 31, 2018 and December 31, 2017 and 2016, were prepared by SIS and NSAI, our independent petroleum engineers, respectively. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates.

Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a roll-forward of the total proved reserves for the year ended December 31, 2018, 2017, and 2016 as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year:

| | Natural Gas (Bcf) | Natural Gas Liquids (MBbl) | Oil (MBbl) | TOTAL (Bcfe) |
|---|---|---|---|---|
| End of year, December 31, 2015 | 274.1 | 7,758.7 | 4,693.1 | 348.8 |
| Revisions | (0.1) | 1,273.7 | 1,196.8 | 14.8 |
| Extensions and discoveries | 175.4 | 2,156.0 | 1,300.2 | 196.1 |
| Acquisitions | 3.8 | 24.8 | 15.1 | 4.1 |
| Divestitures | (5.9) | (91.5) | (703.7) | (10.7) |
| Production | (60.9) | (2,446.2) | (1,343.8) | (83.7) |
| End of year, December 31, 2016 | 386.4 | 8,675.5 | 5,157.7 | 469.4 |
| Revisions | 515.1 | 20,327.3 | 9,746.8 | 695.6 |
| Extensions and discoveries | 274.4 | 15,598.8 | 6,192.9 | 405.1 |
| Acquisitions | 1.6 | 42.6 | 5.8 | 1.9 |
| Production | (87.4) | (2,713.6) | (1,622.4) | (113.4) |
| End of year, December 31, 2017 | 1,090.1 | 41,930.6 | 19,480.8 | 1,458.6 |
| Revisions | 5.6 | (8,307.5) | 231.2 | (42.8) |
| Extensions and discoveries | 515.8 | 4,059.4 | 2,995.7 | 558.1 |
| Acquisitions | 9.9 | 551 | 522 | 16.3 |
| Divestitures | (0.2) | — | — | (0.2) |
| Production | (90.0) | (3,503.0) | (2,377.8) | (125.3) |
| End of year, December 31, 2018 | 1,531.2 | 34,730.9 | 20,852.1 | 1,864.7 |
| Proved developed reserves: | | | | |
| December 31, 2015 | 209.5 | 7,245.7 | 4,239.2 | 278.4 |
| December 31, 2016 | 226.1 | 7,520.0 | 4,439.5 | 297.8 |
| December 31, 2017 | 334.6 | 13,782.9 | 6,449.6 | 456.0 |
| December 31, 2018 | 501.0 | 20,213.8 | 8,058.7 | 670.7 |
| Proved undeveloped reserves: | | | | |
| December 31, 2015 | 64.5 | 513.0 | 453.9 | 70.3 |
| December 31, 2016 | 160.4 | 1,155.5 | 718.1 | 171.6 |
| December 31, 2017 | 755.5 | 28,147.7 | 13,031.2 | 1,002.6 |
| December 31, 2018 | 1,030.2 | 14,517.2 | 12,793.4 | 1,194.1 |

*2016 Changes in Reserves*

- Extensions of 196.1 Bcfe primarily from the development of the Company's Utica asset.
- Positive revisions of 14.8 Bcfe as a result of a negative revision of 50.8 Bcfe due to reductions in SEC pricing and a negative revision of 17.9 Bcfe due to changes in differentials. This was offset by a positive revision of 83.5 Bcfe primarily driven by proved developed producing wells in aggregate outperforming the previous estimate.

- 4.1 Bcfe related to acquiring proved developed and proved undeveloped leasehold acreage in the Utica Shale.
- 10.7 Bcfe related to divesting proved developed and proved undeveloped leasehold acreage in the Utica Shale.

*2017 Changes in Reserves*

- Extensions of 405.1 Bcfe primarily from 361.0 Bcfe of development of the Company's operated Utica asset. The Company also added 0.3 Bcfe from one non-operated Utica well through development. In addition, the Company proved 43.8 Bcfe from 3 Ohio Marcellus wells due to development in the Ohio Marcellus asset.
- Positive revisions of 695.6 Bcfe as a result of a positive revision of 607.2 Bcfe due to improvements in SEC pricing, a positive revision of 61.4 Bcfe due to changes in pricing differentials, and a positive revision of 69.6 Bcfe primarily driven by proved developed producing wells in aggregate outperforming the previous estimate. This was offset by a negative revision of 42.6 Bcfe due a decision to not develop certain proved, undeveloped reserves within five years.

*2018 Changes in Reserves*

- Extensions of 558.1 Bcfe from the development of 148.3 Bcfe of unproved wells to proved developed, 398.2 Bcfe from the development of the Company's operated Utica asset and 11.6 Bcfe from the Company's operated Marcellus asset.
- 16.3 Bcfe related to acquiring proved developed leasehold acreage in the Indian Castle/Flat Creek and Utica Shales.
- 0.2 Bcfe related to divesting a non-operated proved developed well in the Utica Shale.
- Negative revisions of 42.8 Bcfe as a result of a positive revision of 15.0 Bcfe due to improvements in SEC pricing, a positive revision of 6.8 Bcfe due to changes in pricing differentials and a positive revision of 67.5 Bcfe primarily driven by proved developed producing wells outperforming the previous estimate. This was offset by a negative revision of 98.0 Bcfe due to changes in well spacing and 34.1 Bcfe due to changes in the five year development plan.

### *(d) Standardized Measure of Discounted Future Net Cash Flows*

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties, and consideration of expected future economic and operating conditions. The estimates of future cash flows and future production and development costs as of December 31, 2018 and 2017 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%. The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows at December 31, 2018, 2017, and 2016 (in thousands):

| | December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Future cash inflows (total revenues) | $ 6,730,000 | $ 4,750,238 | $1,143,142 |
| Future production costs | (2,964,098) | (2,332,310) | (725,724) |
| Future development costs (capital costs) | (855,932) | (879,399) | (116,988) |
| Future income tax expense | (136,472) | — | — |
| Future net cash flows | 2,773,498 | 1,538,529 | 300,430 |
| 10% annual discount for estimated timing of cash flows | (1,444,188) | (808,843) | (94,449) |
| Standardized measure of Discounted Future Net Cash Flow | $ 1,329,310 | $ 729,686 | $ 205,981 |

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

### *(e) Changes in the Standardized Measure of Discounted Future Net Cash Flows*

A summary of the changes in the standardized measure of discounted future net cash flows are contained in the table below (in thousands):

| | December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Standardized Measure, beginning of the year | $ 729,686 | $ 205,981 | $ 212,865 |
| Net change in prices and production costs | 369,578 | 653,347 | (33,507) |
| Net change in future development costs | 87,466 | (385,042) | 1,552 |
| Sales, less production costs | (321,802) | (226,324) | (99,768) |
| Extensions | 363,708 | 135,734 | 79,941 |
| Acquisitions | 7,468 | 2,365 | 1,045 |
| Divestitures | (20) | — | (5,231) |
| Revisions of previous quantity estimates | 19,910 | 322,917 | 15,754 |
| Previously estimated development costs incurred | 65,035 | 34,102 | 4,886 |
| Net changes in taxes | (37,345) | — | — |
| Accretion of discount | 72,969 | 20,598 | 21,287 |
| Changes in timing and other | (27,343) | (33,992) | 7,157 |
| Standardized Measure, end of year | $1,329,310 | $ 729,686 | $ 205,981 |

**Exhibit 31.1**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, John K. Reinhart, Chief Executive Officer of Montage Resources Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2018 of Montage Resources Corporation (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 15, 2019

/s/ John K. Reinhart
John K. Reinhart
*Chief Executive Officer*

**Exhibit 31.2**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**
**PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)**
**OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Michael Hodges, Chief Financial Officer of Montage Resources Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2018 of Montage Resources Corporation (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2019

/s/ Michael Hodges
Michael Hodges
*Chief Financial Officer*

**Exhibit 32.1**

**CERTIFICATION OF**
**CHIEF EXECUTIVE OFFICER**
**OF MONTAGE RESOURCES CORPORATION**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with this Annual Report on Form 10-K of Montage Resources Corporation for the year ended December 31, 2018, I, John K. Reinhart, Chief Executive Officer of Montage Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2018 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2018 fairly presents, in all material respects, the financial condition and results of operations of Montage Resources Corporation for the periods presented therein.

Date: March 15, 2019

/s/ John K. Reinhart
John K. Reinhart
*Chief Executive Officer*

**Exhibit 32.2**

**CERTIFICATION OF**
**CHIEF FINANCIAL OFFICER**
**OF MONTAGE RESOURCES CORPORATION**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with this Annual Report on Form 10-K of Montage Resources Corporation for the year ended December 31, 2018, I, Michael Hodges, Chief Financial Officer of Montage Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2018 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2018 fairly presents, in all material respects, the financial condition and results of operations of Montage Resources Corporation for the periods presented therein.

Date: March 15, 2019

/s/ Michael Hodges
Michael Hodges
*Chief Financial Officer*

## EXECUTIVE MANAGEMENT:

**John K. Reinhart** – President and Chief Executive Officer, Director

**Michael L. Hodges** – Executive Vice President and Chief Financial Officer

**Oleg E. Tolmachev** – Executive Vice President and Chief Operating Officer

**Matthew H. Rucker** – Executive Vice President, Resource Planning and Development

**Paul M. Johnston** – Executive Vice President and General Counsel

### INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

**Grant Thornton LLP**
Cleveland, Ohio

### TRANSFER AGENT AND REGISTRAR

Computershare Investor Services
462 South 4th Street
Louisville KY 40245
Toll Free: 1.877.373.6374
Investor Centre Portal
www.computershare.com/investor

### INVESTOR RELATIONS

**Douglas A. Kris** – Vice President, Investor Relations

Montage Resource Corporation
122 West John Carpenter Freeway
Suite 300
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Direct: 814.325.2059
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### MONTAGE RESOURCES COMMON STOCK

Common stock of Montage Resources is traded on the New York Stock Exchange under the symbol MR.

## BOARD OF DIRECTORS:

**Randall M. Albert** – Director

**Mark E. Burroughs, Jr.** – Director

**Eugene I. Davis** – Director

**Don Dimitrievich** – Director

**Michael C. Jennings** – Chairman of the Board

**Richard D. Paterson** – Director

**D. Martin Phillips** – Director

**John K. Reinhart** – President & Chief Executive Officer, Director

**Douglas E. Swanson, Jr.** – Director

**Robert L. Zorich** – Director

MONTAGE
RESOURCES


**CORPORATE HEADQUARTERS**

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