MANAGEMENT'S DISCUSSION AND ANALYSIS AND
CONSOLIDATED FINANCIAL STATEMENTS

Ascent Resources Utica Holdings, LLC

As of December 31, 2017 and 2016, and for the years ended December 31, 2017, 2016 and 2015.

**ASCENT RESOURCES UTICA HOLDINGS, LLC**
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**Management's Discussion and Analysis of Financial Condition and Results of Operations.**

*Our Management's Discussion and Analysis of our Financial Condition and Results of Operations (MD&A) should be read in conjunction with our consolidated financial statements and related notes, included herein. The following discussion and analysis contains forward-looking statements that involve known and unknown risks, uncertainties and assumptions. The forward-looking statements are not historical facts, but rather reflect our future plans, estimates, beliefs and expected performance. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.*

*Unless otherwise indicated or the context otherwise requires, references in this MD&A section to "we", "our" and "us" refer to Ascent Resources Utica Holdings, LLC together with its wholly-owned subsidiaries.*

**Overview**

Ascent Resources Utica Holdings, LLC (ARUH) is an independent exploration and production company engaged in the acquisition, exploration and development of natural gas and oil properties in the Utica Shale of the Appalachian Basin. We are a wholly-owned subsidiary of Ascent Resources Operating, LLC (the Member), an indirect wholly-owned subsidiary of Ascent Resources, LLC (the Parent). We were formed in 2013, by our private equity sponsors, primarily The Energy & Minerals Group (EMG) and First Reserve Corporation, to utilize our technical expertise to acquire and exploit assets in the Utica Shale. Our asset base is concentrated in southern Ohio, where we target primarily the Point Pleasant interval of the Utica Shale, one of the premier North American natural gas and oil shale plays. Our largely contiguous footprint of approximately 195,000 net acres lies within the core of the southern Utica Shale and, as supported by our drilling results and those of offset operators, offers development opportunities with predictable and repeatable production profiles, low breakeven costs and industry-leading rates of return. We have strategically assembled our position in the southern Utica Shale because of advantageous geological and petrophysical characteristics, including significant overpressure, strong formation seals, favorable rock mechanics (fracturability) and low water saturations in this region, resulting in substantial hydrocarbons in place and well results that are among the most productive in the Utica Shale.

We are continuously focused on enhancing our drilling and completion techniques, minimizing costs and maximizing the ultimate recovery of natural gas, oil and natural gas liquids (NGL) from our assets, with the goal of generating top-tier corporate-level returns. The success of our differentiated operational approach is evident in the results of our operated wells. For example, in October 2017, we achieved one bcfe per day of net production from only 185 gross (156 net) operated wells.

**Segment and Geographical Information**

We have one reportable operating segment in the United States and a single company-wide management team that administers all properties as a whole rather than by distinct operating segments. We measure financial performance as a single enterprise and not on a geographical basis.

**2017 Highlights**

- In November, we acquired and contemporaneously sold unproved leasehold and producing and non-producing natural gas and oil properties located in the Utica Shale in Ohio in the following series of transactions:
    - We acquired approximately 16,400 net acres, which included unproved leasehold and producing and non-producing natural gas and oil properties (the Utica Acquisition), for a purchase price of $62.0 million, subject to customary closing adjustments. Partial interests in these acquired assets were divested as described below.
    - We sold a partial interest in producing and non-producing natural gas and oil properties, which included certain properties acquired in the Utica Acquisition and other properties partially developed by us, for a sales price of $74.6 million, subject to customary closing adjustments (the Utica Divestiture). The proceeds were used to fund the Utica Acquisition and for general corporate purposes. As part of the Utica Divestiture, we entered into a development agreement whereby the buyer is required to pay 75.0% of our development costs (carried costs) for the development of 34 wells in exchange for 58.5% of our working interest. As of December 31, 2017, the buyer had carried $4.4 million of our associated development costs.
    - In conjunction with the joint venture participation agreement related to an area of mutual interest (AMI) with one of our joint venture partners, we sold 4,400 net acres, which included a partial interest in certain producing and non-producing natural gas and oil properties and 3,270 net acres, which were acquired in the Utica Acquisition. Additionally, we sold 1,130 net unproved acres within the AMI. The total sales price for this transaction was $21.8 million, subject to customary closing adjustments. The consideration for the sales price was a reduction to our cash carry obligations to the joint venture

partner. See Note 8, *Joint Venture Commitments*, of the notes to our consolidated financial statements for more details of this transaction.

- In November, we satisfied the remaining carry bank commitment related to one of our joint venture participation agreements. See Note 8, *Joint Venture Commitment*s, of the notes to our consolidated financial statements for more details of this commitment.
- In October, we executed the first amendment to our $1.5 billion revolving credit facility (2017 Credit Facility), which was established in April 2017 and replaced the existing credit facility (2016 Credit Facility). The borrowing base under the 2017 Credit Facility was increased from $650.0 million to $925.0 million and the sublimit for letters of credit was increased from $450.0 million to $647.5 million.
- In August, we, together with Utica Minerals Development, LLC (UMD), acquired approximately 10,400 net acres of primarily unproved leasehold in the Utica Shale in Ohio (the Acquisition Properties) for a purchase price of $98.0 million, subject to customary closing adjustments. At closing, we received an undivided 25% interest in the Acquisition Properties for $33.4 million with UMD receiving the remaining undivided 75% interest in the Acquisition Properties. Pursuant to an agreement between us and UMD (the Earn-In Agreement), we can earn an additional undivided 25% interest in the Acquisition Properties from UMD by drilling and operating a designated set of wells on the Acquisition Properties and carrying 100% of UMD's drilling and completion costs (carried costs) of approximately $22.0 million. As of December 31, 2017, the remaining carried cost balance was approximately $20.8 million. Upon our full payment of the UMD carried costs, each party will own an undivided 50% interest in the Acquisition Properties. In accordance with the Earn-In Agreement, we will have the right to pay the outstanding balance of the carry, and any prepayment penalty (if applicable), at any time prior to December 31, 2018 (the Term Date). Should we fail to satisfy the UMD carried costs by the Term Date, we will be required to forfeit and assign to UMD our rights and title in any interest earned by us pursuant to the Earn-In Agreement. See Note 7, *UMD Agreements*, of the notes to our consolidated financial statements for a discussion of the development agreement with UMD.
- In April, we closed on the issuance of $1.5 billion in aggregate principal amount of 10.0% senior unsecured notes (2022 Notes). The net proceeds were used to repay and retire all of our outstanding second lien term loans (Second Lien Term Loans) and for general corporate purposes.
- In March, we retired $11.1 million of outstanding principal and accrued and unpaid interest associated with certain Convertible Notes (defined below) contributed to us by the Member.

**Well Data**

As of December 31, 2017, we held an interest in approximately 388 gross (177 net) productive wells, including 374 gross (177 net) wells in which we held a working interest and 14 gross wells in which we held an overriding or royalty interest. Of the wells in which we had a working interest, 348 gross (163 net) were classified as productive natural gas wells and 26 gross (14 net) were classified as productive oil wells. We operated approximately 199 gross (164 net) of our productive wells in which we had a working interest. During 2017, we drilled 88 gross (75 net) wells as operator and participated in another 12 gross (1 net) wells drilled by other operators. We operated approximately 96% of our daily production volumes in 2017.

**Drilling Activity**

The following table describes the productive wells we drilled or participated in during years ended December 31, 2017, 2016 and 2015:

| | 2017 | | 2016 | | 2015 | |
|---|---|---|---|---|---|---|
| | Productive Wells | | Productive Wells | | Productive Wells | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development | 100 | 76 | 85 | 27 | 120 | 47 |

As of December 31, 2017, we had 73 gross (49 net) wells in the process of being drilled or completed. We did not drill any exploratory or dry development wells during the years ended December 31, 2017, 2016 and 2015.

**Developed and Undeveloped Acreage**

Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether such acreage contains proved reserves. Developed acreage is acreage spaced or assigned to productive wells; however, it does not include undrilled acreage held by production under the terms of the lease. A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional working interests owned in gross acres equals one.

The following table sets forth our gross and net acres of developed and undeveloped natural gas and oil leasehold as of December 31, 2017:

| Developed Acres | | Undeveloped Acres | | Total Acres | |
|---|---|---|---|---|---|
| Gross | Net | Gross | Net[(a)] | Gross | Net |
| 61,243 | 38,492 | 185,702 | 156,287 | 246,945 | 194,779 |

(a) Approximately 44% of our net undeveloped leasehold acreage is held by production, with only 86,775 net acres subject to lease expiration.

The following table sets forth the number of total net undeveloped acres as of December 31, 2017 that will expire unless production is established within the spacing units covering the acreage prior to the lease expiration dates or unless such leasehold rights are extended or renewed:

| | Acres Expiring | |
|---|---|---|
| | Gross | Net |
| 2018 | 36,468 | 31,271 |
| 2019 | 23,388 | 21,132 |
| 2020 | 11,604 | 9,430 |
| Thereafter | 28,486 | 24,942 |
| Total | 99,946 | 86,775 |

**Production Volumes, Sales Prices, Lease Operating Expenses and Gathering, Processing and Transportation Expenses**

The following table sets forth information regarding our production volumes, average sales prices received, lease operating expenses and gathering, processing and transportation expenses for the periods indicated. Average sales prices listed in the table below are based on thousand cubic feet (mcf) of natural gas and barrels (bbls) of oil and NGL.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| **Net Production Volumes:** | | | |
| Natural gas (mmcf) | 240,980 | 109,714 | 38,355 |
| Oil (mbbls) | 2,492 | 2,035 | 1,706 |
| NGL (mbbls) | 3,286 | 2,588 | 1,242 |
| Natural Gas Equivalent (mmcfe) | 275,653 | 137,451 | 56,044 |
| **Average Sales Prices:** | | | |
| Natural gas ($/mcf) | $ 2.93 | $ 2.39 | $ 2.62 |
| Oil ($/bbl) | $ 44.71 | $ 33.19 | $ 36.60 |
| NGL ($/bbl) | $ 23.45 | $ 14.23 | $ 12.20 |
| Natural Gas Equivalent ($/mcfe) | $ 3.25 | $ 2.67 | $ 3.17 |
| **Average Sales Prices, including the effects of settled derivatives:** | | | |
| Natural gas ($/mcf) | $ 3.00 | $ 2.45 | $ 2.64 |
| Oil ($/bbl) | $ 47.35 | $ 32.57 | $ 36.60 |
| NGL ($/bbl) | $ 23.45 | $ 14.23 | $ 12.20 |
| Natural Gas Equivalent ($/mcfe) | $ 3.33 | $ 2.70 | $ 3.19 |
| **Operating Expenses ($/mcfe):** | | | |
| Lease operating expenses | $ 0.13 | $ 0.18 | $ 0.38 |
| Gathering, processing and transportation expenses | $ 1.24 | $ 1.36 | $ 1.55 |

## Natural Gas, Oil and NGL Reserves

The following table sets forth our proved reserves as of December 31, 2017. All of our estimated reserves are located within the Utica Shale.

| | December 31, 2017 | | | |
|---|---|---|---|---|
| | Natural Gas (mmcf) | Oil (mbbls) | NGL (mbbls) | Total (mmcfe) |
| Proved developed reserves[(a)] | 1,445,354 | 8,762 | 14,622 | 1,585,659 |
| Proved undeveloped reserves | 2,466,492 | 13,403 | 20,885 | 2,672,218 |
| Total | 3,911,846 | 22,165 | 35,507 | 4,257,877 |

(a) Approximately 166.9 bcfe, or 11%, of our proved developed reserves were non-producing.

The table below sets forth information as of December 31, 2017, with respect to our estimated proved reserves, the associated estimated future net revenue, the present value (discounted at an annual rate of 10%) of the associated estimated future net revenue (PV-10) and the standardized measure of discounted cash flows. Neither the estimated future net revenue, PV-10 nor the standardized measure is intended to represent the current market value of the estimated natural gas, oil and NGL reserves we own. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs under existing economic conditions as of December 31, 2017. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2017. The prices used in our reserve reports were $2.98 per mcf of natural gas and $51.34 per bbl of oil, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the prices used to value our commodity derivative instruments in place as of December 31, 2017. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. PV-10 is a non-GAAP measure that typically differs from the standardized measure, because the former does not include the effects of estimated future income tax expense. However, because we are a disregarded entity for income tax purposes, we have estimated no future income tax expense and the two measures are the same as of December 31, 2017. PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis.

| | December 31, 2017 | | |
|---|---|---|---|
| | Proved Developed | Proved Undeveloped | Total Proved |
| | | ($ in thousands) | |
| Estimated future net revenue | $ 2,263,929 | $ 2,606,278 | $ 4,870,207 |
| PV-10 | $ 1,347,710 | $ 948,869 | $ 2,296,579 |
| Standardized measure[(a)] | | | $ 2,296,579 |

(a) See Note 11, *Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves*, of the notes to our consolidated financial statements included in this report for further discussion.

As of December 31, 2017, our estimated proved reserves included approximately 2.7 tcfe of reserves classified as proved undeveloped, compared to approximately 1.1 tcfe as of December 31, 2016. The table below is a summary of changes in our proved undeveloped reserves (PUDs) for 2017:

| | Total (mmcfe) |
|---|---|
| Proved undeveloped reserves at December 31, 2016 | 1,055,199 |
| Extensions, discoveries and other additions | 2,219,815 |
| Revisions | 307,112 |
| Purchases of reserves | 37,492 |
| Sales of reserves | (28,695) |
| Developed | (918,705) |
| Proved undeveloped reserves at December 31, 2017 | 2,672,218 |

As of December 31, 2017, there were no PUDs that had remained undeveloped for five years or more. Our proved undeveloped extensions and discoveries of approximately 2.2 tcfe of reserves resulted from the continued development of our Utica Shale acreage. Revisions of previous estimates included upward revisions of 148.6 bcfe due to improved drilling and operating efficiencies, including the impact from extended laterals, upward revisions of 338.3 bcfe due to higher commodity prices and downward revisions of 179.8 bcfe resulting primarily from removing PUDs where it was determined development would occur outside of our five year development plan. We added 37.5 bcfe of proved undeveloped reserves through acquisitions and reduced our proved undeveloped reserves through divestitures by 28.7 bcfe. In 2017, we invested approximately $421.8 million to convert 918.7 bcfe to proved developed reserves. In 2018, we estimate that we will invest approximately $384.8 million for PUD conversion.

The future net revenues attributable to our estimated PUDs of $2.6 billion as of December 31, 2017, and associated PV-10 of $948.9 million, have been calculated assuming that we will expend approximately $1.4 billion to develop these reserves ($384.8 million in 2018, $195.6 million in 2019, $463.5 million in 2020, $203.2 million in 2021 and $161.4 million in 2022), although the amount and timing of these expenditures will depend on a number of factors, including, but not limited to, actual drilling results, service costs, commodity prices and the availability of capital. Our developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unpredictable factors such as unexpected drilling results, title issues and infrastructure availability or constraints.

*Evaluation and Review of Reserves*

Our proved reserve estimates as of December 31, 2017 were prepared by Software Integrated Solutions (SIS) (formerly known as PetroTechnical Services), a Division of Schlumberger Technology Corporation, our independent reserve engineers. Within SIS, the technical person primarily responsible for preparing the estimates set forth in the reserve reports is Mr. Charles M. Boyer II, PG, CPG. Mr. Boyer has over 25 years of domestic and international experience in the estimation and evaluation of natural gas and oil reserves. He is an active member of the Society of Petroleum Evaluation Engineers, the Society of Petroleum Engineers and the American Association of Petroleum Geologists. As technical principal, Mr. Boyer meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in applying industry standard practices to engineering evaluations as well as applying SEC and other industry reserves definitions and guidelines. Mr. Boyer does not own an interest in any of our properties, nor is he employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical team meets with our independent reserve engineers periodically during the preparation of the year-end reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information that is reviewed and verified to the independent reserve engineers for our properties, such as ownership interest, natural gas, oil and NGL production data, well test data, commodity prices, operating and development costs, and realized pricing differentials and marketing contract fees. Mr. Daniel E. Hensley, our Vice President-Exploration and Resource Development, is primarily responsible for overseeing the preparation of all our reserve estimates. Mr. Hensley is a petroleum engineer with approximately 19 years of reservoir estimation and operations experience, and our engineering and geoscience staff have an average of approximately 12 years of industry experience.

The preparation of our historical 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 of our proved undeveloped wells to ensure that the timing and future rates of production are consistent with current development plans and our financial ability to develop such reserves within five years;
- Preparation of reserve estimates by Mr. Hensley or under his direct supervision; and
- Review by our Chief Executive Officer, Chief Financial Officer and Chief Operating Officer of all of our reported reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped additions.

**Selected Financial Data**

The following table presents summary consolidated financial data for each of the periods indicated. Summary historical financial data as of and for the years ended December 31, 2017, 2016, and 2015 is derived from the audited consolidated financial statements. The financial data included may not be indicative of our future results of operations, financial condition and cash flows.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| **Statements of operations data:** | | | |
| **Revenues:** | | | |
| Natural gas | $ 706,866 | $ 262,765 | $ 100,311 |
| Oil | 111,441 | 67,551 | 62,461 |
| NGL | 77,054 | 36,833 | 15,146 |
| Commodity derivative gain (loss) | 212,046 | (86,434) | (2,005) |
| Total Revenues | 1,107,407 | 280,715 | 175,913 |
| **Operating Expenses:** | | | |
| Lease operating expenses | 35,259 | 24,061 | 21,119 |
| Gathering, processing and transportation expenses | 341,765 | 186,300 | 86,973 |
| Production and ad valorem taxes | 14,050 | 7,623 | 2,504 |
| Exploration expenses | 186,152 | 269,982 | 85,394 |
| General and administrative expenses, including related party | 46,325 | 39,146 | 71,604 |
| Litigation settlement (benefit) expense | — | (4,147) | 92,974 |
| Natural gas and oil depreciation, depletion and amortization | 305,573 | 229,038 | 133,410 |
| Depreciation and amortization of other assets | 1,905 | 1,864 | 660 |
| Impairment of other property and equipment | — | 2,222 | — |
| Loss on divestiture of natural gas and oil properties | — | — | 205,638 |
| Total Operating Expenses | 931,029 | 756,089 | 700,276 |
| **Income (Loss) From Operations** | 176,378 | (475,374) | (524,363) |
| **Other (Expense) Income:** | | | |
| Interest expense, net | (69,062) | (88,159) | (286,853) |
| Acquisition obligation accretion expense | (4,290) | (10,108) | (17,118) |
| Change in fair value of embedded derivative | (19,261) | 3,616 | 211,593 |
| (Losses) gains on purchases or exchanges of debt | (114,052) | 207,470 | (25,831) |
| Other income | 1,572 | 2,001 | 2,596 |
| Total Other (Expense) Income | (205,093) | 114,820 | (115,613) |
| **Net Loss** | $ (28,715) | $ (360,554) | $ (639,976) |
| **Balance sheets data (at period end):** | | | |
| Cash and cash equivalents | $ 119,215 | $ 268,493 | $ 84,187 |
| Total assets | $ 4,213,869 | $ 3,793,458 | $ 3,304,038 |
| Total long-term debt, net | $ 1,564,774 | $ 1,325,325 | $ 2,373,766 |
| Total liabilities | $ 2,031,369 | $ 1,726,275 | $ 2,715,470 |
| Total liabilities and Member’s equity | $ 4,213,869 | $ 3,793,458 | $ 3,304,038 |

## Liquidity and Capital Resources

*Liquidity Overview*

Our natural gas, oil and NGL operations, including our exploration, drilling and production operations, are capital intensive activities that require access to significant capital. We continually evaluate our capital needs and compare them to our capital resources. Historically, our primary sources of funds have been through equity contributions from our Parent, proceeds from the issuance of debt and asset sales. Equity contributions from our Parent, cash on hand, cash flow from operations, future draws on our credit facility and other capital market transactions will be our primary sources of liquidity in the future.

As of December 31, 2017, we had a cash balance of $119.2 million. In April 2017, we issued $1.5 billion in aggregate principal amount of 2022 Notes in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. Net proceeds were $1.466 billion. The proceeds were used to repay and retire all of our outstanding Second Lien Term Loans and for general corporate purposes. Contemporaneously, we entered into the 2017 Credit Facility to replace our existing 2016 Credit Facility with a fully committed initial borrowing base of $650.0 million and a maturity date of December 31, 2021. In October 2017, the borrowing base under the 2017 Credit Facility was redetermined and adjusted to a fully committed amount of $925.0 million. As of March 7, 2018, we had no borrowings under the 2017 Credit Facility with $427.7 million letters of credit outstanding. Based on our current cash balance, credit facility availability and expected operating cash flows, we anticipate being able to satisfy all of our financial obligations and commitments for the next twelve months.

We anticipate a significant increase in our revenues in 2018 due to expected increased production compared to 2017. Substantial capital expenditures are required to replace reserves as well as sustain and increase production. A substantial or extended decline in natural gas, oil and NGL prices could have a material impact on our financial position, results of operations, cash flows and quantities of natural gas, oil and NGL reserves that may be economically produced. Furthermore, in a low commodity price environment our ability to generate positive operating cash flows, maintain our natural gas, oil and NGL production and reserves, raise additional capital, sell assets, or take any other action to improve liquidity is subject to risks and uncertainties that exist in our industry, some of which we may not be able to anticipate or control.

*Sources of Funds*

The following table presents the sources of cash and cash equivalents:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| Cash provided by (used in) operating activities | $ 485,444 | $ 92,792 | $ (159,954) |
| Proceeds from divestitures of natural gas and oil properties | 79,329 | 16,664 | 385,964 |
| Proceeds from sale of other property and equipment | 28 | — | 15,882 |
| Reduction in deposits on pipeline transportation | 151,193 | — | 13,705 |
| Proceeds from issuance of long-term debt, net | 1,466,250 | — | 922,210 |
| Contributions from Member | 132,000 | 1,331,719 | 385,000 |
| **Total Sources of Cash and Cash Equivalents** | $ 2,314,244 | $ 1,441,175 | $ 1,562,807 |

Net cash flow provided by operating activities was approximately $485.4 million for 2017, compared to $92.8 million provided by operating activities for 2016 and $160.0 million used in operating activities for 2015. The increase in operating cash flow from 2016 to 2017 was primarily the result of higher realized prices and increased natural gas, oil and NGL production. The increase in operating cash flow from 2015 to 2016 was primarily the result of increased natural gas, oil and NGL production and a positive change in working capital levels.

*Uses of Funds*

The following table presents the uses of cash and cash equivalents:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| **Natural Gas and Oil Expenditures:** | | | |
| Drilling and completion costs | $ (653,942) | $ (268,082) | $ (760,435) |
| Acquisitions of natural gas and oil properties | (323,341) | (267,582) | (217,677) |
| Interest capitalized on unproved leasehold | (106,549) | (160,719) | — |
| Additions to deposits on pipeline transportation | — | (41,811) | — |
| Total Natural Gas and Oil Expenditures | (1,083,832) | (738,194) | (978,112) |
| **Other Uses of Cash and Cash Equivalents:** | | | |
| Repayment of debt | (1,290,264) | (464,649) | (477,250) |
| Additions to other property and equipment | (285) | (715) | (13,689) |
| Additions to other long-term assets | — | — | (21,041) |
| Cash paid for debt issuance costs | (18,142) | (15,474) | (43,657) |
| Cash paid for debt prepayment costs | (70,999) | (667) | — |
| Repayment of note payable to third party | — | (37,170) | — |
| Total Other | (1,379,690) | (518,675) | (555,637) |
| **Total Uses of Cash and Cash Equivalents** | $ (2,463,522) | $ (1,256,869) | $ (1,533,749) |

**Certain Indebtedness**

*Credit Facilities*

*2017 Credit Facility*. The amount available to be borrowed under the 2017 Credit Facility is subject to a borrowing base that is redetermined semiannually as of each April 1 and October 1 based on our proved natural gas, oil and NGL reserves, estimated cash flows from these reserves and our commodity derivative positions. In October 2017, the borrowing base under the 2017 Credit Facility was increased to $925.0 million and the sublimit for letters of credit was increased to $647.5 million. As of December 31, 2017, we had no borrowings under the 2017 Credit Facility with $427.7 million of letters of credit outstanding. As of March 7, 2018, we had no borrowings under the 2017 Credit Facility with $427.7 million of letters of credit outstanding.

Principal amounts borrowed are payable on the maturity date and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the prime rate announced by the administrative agent, (ii) the Federal Reserve Bank of New York federal funds rate plus 0.5% and (iii) the rate for one month Eurodollar loans, plus an applicable margin ranging from 1.75% to 2.75% per annum. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 2.75% to 3.75% per annum. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. The 2017 Credit Facility is secured by liens on substantially all of our properties, including our natural gas and oil properties, and guarantees from our subsidiaries other than any subsidiary that we have designated as an unrestricted subsidiary. As of December 31, 2017, we were in compliance with all applicable financial covenants under the 2017 Credit Facility. See Note 4 of the notes to our consolidated financial statements for further discussion of the terms of the 2017 Credit Facility.

*2016 Credit Facility.* The 2016 Credit Facility had a borrowing base of $100.0 million and was scheduled to mature on June 30, 2018. In April 2017, the 2016 Credit Facility was replaced by the 2017 Credit Facility. This resulted in the write-off of $5.6 million in unamortized debt issuance costs.

*Senior Notes*

The 2022 Notes are due on April 1, 2022, and interest is payable at an annual rate of 10.0% on April 1 and October 1 of each year, which commenced on October 1, 2017. At any time prior to April 1, 2020, we may redeem up to 35% of the aggregate principal amount of the 2022 Notes at a price equal to 110% of the principal amount, plus accrued and unpaid interest to, but excluding, the redemption date, using the net proceeds of certain equity offerings and subject to certain conditions. Additionally, at any time prior to April 1, 2020, we may redeem some or all of the 2022 Notes subject to a make-whole premium plus accrued and unpaid interest to, but excluding, the redemption date. On or after April 1, 2020, we may redeem some or all of the 2022 Notes at the applicable redemption prices (expressed as percentages of principal amount) set forth in the table below:

| Redemption on or after | Redemption Price |
|---|---|
| April 1, 2020 | 107.5% |
| April 1, 2021 | 105.0% |
| October 1, 2021 and thereafter | 100.0% |

We are not prohibited from acquiring the 2022 Notes by means other than a redemption, whether pursuant to a tender offer, open market purchase or otherwise, so long as the acquisition does not violate the terms of the indenture. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2022 Notes at a purchase price in cash equal to 101% of the aggregate principal amount of the 2022 Notes to be repurchased, plus accrued and unpaid interest.

The 2022 Notes are our senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured debt, and will rank senior in right of payment to all our future subordinated debt. The 2022 Notes will be effectively subordinated to all of our existing and future secured debt to the extent of the value of the collateral securing such indebtedness.

As of December 31, 2017, we were in compliance with all applicable covenants of the 2022 Notes indenture. See Note 4 of the notes to our consolidated financial statements for further discussion of the terms of the 2022 Notes.

*Convertible Notes*

In February 2014, we issued $750.0 million of convertible notes due 2021 (Convertible Notes). In August 2014, we issued an additional $250.0 million of Convertible Notes. As a result of the offer to exchange (Exchange Offer) the outstanding Convertible Notes for newly issued Convertible Notes due 2021 (New Convertible Notes) in February 2016, and the redemption of the New Convertible Notes in April 2016, an aggregate carrying value of $97.3 million remained outstanding as of December 31, 2017.

Interest on the Convertible Notes may be paid in cash or in kind semi-annually in arrears on March 1 and September 1 of each year and originally was payable at an annual rate of 3.5%. On March 1, 2016, the interest rate began escalating by 0.5% on each interest payment date, subject to a maximum interest rate of 6.5% per annum, if a preliminary prospectus relating to a qualified initial public offering (Qualified PO) had not been filed under the Securities Act by such date. We have elected to pay interest in kind on each interest payment date since September 2015 and the interest rate as of December 31, 2017 was 5.5%. The Convertible Notes are subordinated in right of payment to all of our existing and future senior unsecured indebtedness, rank pari passu in right of payment with all of our existing and future subordinated indebtedness, and rank senior in right of payment to all of our existing and future junior subordinated indebtedness. The indenture governing the Convertible Notes does not restrict us or our subsidiaries from incurring additional debt or other liabilities, including secured debt. Following a qualified initial public offering, the Convertible Notes may be converted into common shares of the initial public offering issuer at the option of the noteholders.

The Convertible Notes also provide for cash redemption upon a change in control event at the option of the holders at a premium, which as of December 31, 2017 ranged from 142.9% to 153.8% of the principal amount of the Convertible Notes, depending on the change of control date relative to the date issued. The Convertible Notes are not redeemable prior to a change of control or the closing of a Qualified PO. If the closing of a Qualified PO occurs, we have the option to redeem all of the Convertible Notes that were not converted at a price equal to 100.0% of the principal of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any. See Note 4 of the notes to our consolidated financial statements for further discussion of the terms of the Convertible Notes.

In March 2017, we retired $11.1 million of outstanding principal and accrued and unpaid interest associated with Convertible Notes contributed to us by the Member. Additionally, we wrote off $0.8 million of associated discounts and embedded derivative liability, which resulted in an increase to equity of $11.9 million.

*Second Lien Term Loans*

In September 2013, we entered into the Second Lien Term Loans due September 30, 2018. In April 2017, the outstanding $1.290 billion in principal of the Second Lien Term Loans was repaid using proceeds from the issuance of our 2022 Notes as discussed herein. We paid approximately $1.372 billion in cash, consisting of $1.290 billion applied to the outstanding principal balance, $71.0 million in early redemption fees and $11.0 million in accrued and unpaid interest, resulting in a loss of $108.4 million, including the write-off of unamortized debt issuance costs and discounts, for the year ended December 31, 2017.

**Contractual Obligations and Off-Balance Sheet Arrangements**

We occasionally enter into arrangements that can give rise to contractual obligations and off-balance sheet commitments, such as pipeline transportation commitments, drilling rig commitments, and various other commitments in the ordinary course of business.

The following table summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2017:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years |
| | ($ in thousands) | | | | |
| Long-term debt: | | | | | |
| Principal[a] | $ 1,630,921 | $ — | $ — | $ 1,630,921 | $ — |
| Interest | 676,667 | 150,000 | 300,000 | 226,667 | — |
| Operating lease commitments[b] | 1,593 | 679 | 914 | — | — |
| Operating commitments[c] | 10,587,238 | 566,672 | 1,248,836 | 1,304,310 | 7,467,420 |
| Joint venture commitments[d] | 61,113 | 61,113 | — | — | — |
| Other | 606 | — | 458 | — | 148 |
| Total | $ 12,958,138 | $ 778,464 | $ 1,550,208 | $ 3,161,898 | $ 7,467,568 |

(a) Total principal amount of debt maturities.

(b) See Note 8 of the notes to our consolidated financial statements included in this report for a description of our operating lease commitments.

(c) See Note 8 of the notes to our consolidated financial statements included in this report for a description of pipeline transportation and drilling contracts.

(d) See Note 8 of the notes to our consolidated financial statements included in this report for a description of our joint venture commitments.

**Critical Accounting Policies and Estimates**

Our financial statements are prepared in accordance with Generally Accepted Accounting Principles (GAAP). In connection with preparing our consolidated financial statements, we are required to make assumptions and estimates about future events, and apply judgments that affect the reported amounts of assets, liabilities, revenue, expense and the related disclosures. We base our assumptions, estimates and judgments on historical experience, current trends and other factors that management believes to be relevant at the time we prepare our consolidated financial statements. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that our consolidated financial statements are presented fairly and in accordance with GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ materially from our assumptions and estimates.

Our significant accounting policies are discussed in the notes to our consolidated financial statements. Management believes that the following accounting estimates are those most critical to fully understanding and evaluating our reported financial results, and they require management's most difficult, subjective or complex judgments, resulting from the need to make estimates about the effect of matters that are inherently uncertain.

*Natural Gas, Oil and NGL Reserves*

Estimates of natural gas, oil and NGL reserves and their values, future production rates and future costs and expenses are the most significant of our estimates. Our estimates of proved reserves are based on the quantities of natural gas, oil and NGL, 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 under existing economic conditions, operating methods and government regulations. The accuracy of reserve estimates is a function of the:

- Quality and quantity of available data;
- Interpretation of that data;
- Accuracy of various mandated economic assumptions; and
- Judgment of the independent reserve engineer.

Natural gas, oil and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs and these estimates are inherently uncertain. For example, if estimates of proved reserves decline, our depreciation, depletion and amortization (DD&A) rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of natural gas, oil and NGL properties exceeds fair value and could result in an impairment charge, which would reduce earnings.

We are unable to predict future commodity prices, and the volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. A prolonged period of depressed commodity prices may have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes to our development plans or costs. We cannot predict what reserve revisions may be required in future periods.

*Natural Gas and Oil Properties*

We use the successful efforts method of accounting for natural gas and oil properties, whereby costs incurred to acquire interests in properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Exploration costs, such as most geological and geophysical costs, are expensed as incurred. The successful efforts method of accounting requires that exploratory drilling costs, including capitalized interest, are capitalized in the balance sheet pending determination of whether a well has found proved reserves in economically producible quantities. If proved reserves are found by an exploratory well, the associated capitalized costs become part of proved natural gas and oil properties; provided, however, that if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value, to exploration expense. Acquisition costs of unproved properties are transferred to proved properties to the extent the costs are associated with successful exploration activities.

Proved natural gas and oil properties are reviewed for impairment whenever events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The estimated undiscounted future cash flows expected are compared to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the properties is reduced to its estimated fair value (typically determined using discounted future cash flows). The factors used to estimate fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and discount rates commensurate with the risk associated with realizing the projected cash flows. No impairment of proved natural gas and oil properties was recorded for the years ended December 31, 2017, 2016 or 2015. We cannot predict whether impairment charges may be required in the future as natural gas, oil and NGL prices have a significant impact on determining future impairments.

Unproved natural gas and oil properties primarily consist of undeveloped leasehold costs. Individually significant unproved properties, if any, are assessed for impairment on a property-by-property basis, and if the assessment indicates an impairment, a loss is recognized. For individually insignificant unproved properties, impairment losses are recognized by amortizing to exploration expense the portion of the properties' costs that management estimates will not be transferred to proved properties over the remaining lease term. Our impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms and potential shifts in business strategy employed by management. For the years ended December 31, 2017, 2016 and 2015, we recorded impairments of $183.9 million, $252.8 million and $70.0 million, respectively, to exploration expense related to individually insignificant unproved natural gas and oil properties.

*Natural Gas and Oil Depreciation, Depletion and Amortization*

DD&A of capitalized drilling and completion costs of producing natural gas and oil properties is computed using the unit-of-production method, based on total estimated proved developed natural gas, oil and NGL reserves. Costs of acquiring proved properties, including leasehold acquisition costs and capitalized interest transferred from unproved properties, are depleted using the unit-of-production method based on total estimated proved natural gas, oil and NGL reserves.

*Acquisitions*

As part of our business strategy, we periodically pursue the acquisition of natural gas and oil 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 natural gas, oil and NGL reserves and unproved natural gas and oil properties.

*Asset Retirement Obligations (ARO)*

We recognize liabilities for retirement obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the assets. We recognize the fair value of a retirement obligation in the period in which the obligation is incurred. For natural gas and oil properties, this is the period in which a natural gas or oil well is acquired or drilled. The liability is then accreted to its present value each period, until it is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our natural gas and oil properties and expensed through depletion of the asset. The accretion expense is recorded as a component of natural gas and oil DD&A in our consolidated statements of operations.

The estimates of our future ARO require substantial judgment. We estimate the future costs associated with our retirement obligations, the expected remaining life of the related asset and our credit-adjusted-risk-free interest rate. As revisions to these estimates occur, we may have significant changes to the related asset and its ARO.

If future abandonment cost estimates were to exceed current estimates, or if assets had shortened lives compared to current estimates, we would expect to increase the recorded liability for ARO, which would trigger recognition of additional expense and a reduction to our net income.

*Revenue Recognition*

Revenue from the sale of natural gas, oil and NGL is recognized when title passes, net of royalties due to third parties. We use the sales method of accounting for natural gas imbalances in those circumstances where we have under-produced or over-produced our ownership percentage in a natural gas and oil property. Under this method, a receivable or payable is recognized only to the extent an imbalance cannot be recouped from the future reserves in the underlying properties. At December 31, 2017 and 2016, we had insignificant natural gas imbalances.

*Fair Value of Financial Instruments*

Certain financial instruments are reported at fair value on our consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs based upon the transparency of inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest transparency. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest transparency.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments.

*Commitments and Contingencies*

We are periodically involved in litigation and regulatory proceedings, investigations and disputes for which the outcome is uncertain. A liability is recognized for any contingency that is probable of occurrence and reasonably estimable. Changes in the certainty and the ability to reasonably estimate a loss amount, if any, may result in the recognition and subsequent payment of legal liabilities.

*Derivatives*

We periodically enter into commodity derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility.

All commodity derivative instruments are recognized at their current fair value as either assets or liabilities in the consolidated balance sheets. Changes in the fair value of these commodity derivative instruments are recorded in earnings unless specific hedge accounting criteria are met. We have elected not to designate any of our commodity derivative instruments for hedge accounting treatment. By using commodity derivative instruments, we are exposed to credit risk associated with our hedge counterparties. To minimize such risk, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty. Also, we only enter into derivative contracts with counterparties that are creditworthy. The creditworthiness of our counterparties is subject to periodic review.

The estimates of the fair values of our commodity derivatives require substantial judgment. Valuations are based upon multiple factors such as established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations and are also subject to the risk of our non-performance. This non-performance risk is considered in the valuation of our derivative instruments but to date has not had a material impact on the values of our derivatives.

**New Accounting Pronouncements**

See Note 1 of the notes to our consolidated financial statements for a description of recent accounting pronouncements.

### Results of Operations

The following table sets forth certain information regarding our net production volumes, natural gas, oil and NGL sales, average sales prices received, and certain of our operating expenses for the periods indicated. Average sales prices listed in the table below are based on thousand cubic feet (mcf) of natural gas and barrels (bbls) of oil and NGL.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| **Net Production Volumes:** | | | |
| Natural gas (mmcf) | 240,980 | 109,714 | 38,355 |
| Oil (mbbls) | 2,492 | 2,035 | 1,706 |
| NGL (mbbls) | 3,286 | 2,588 | 1,242 |
| Natural Gas Equivalent (mmcfe) | 275,653 | 137,451 | 56,044 |
| **Natural Gas, Oil, and NGL Sales ($ in thousands):** | | | |
| Natural gas | $ 706,866 | $ 262,765 | $ 100,311 |
| Oil | 111,441 | 67,551 | 62,461 |
| NGL | 77,054 | 36,833 | 15,146 |
| Commodity derivative gain (loss) | 212,046 | (86,434) | (2,005) |
| Total | $ 1,107,407 | $ 280,715 | $ 175,913 |
| **Average Daily Net Production Volumes:** | | | |
| Natural gas (mmcf/d) | 660 | 300 | 105 |
| Oil (mbbls/d) | 7 | 6 | 5 |
| NGL (mbbls/d) | 9 | 7 | 3 |
| Natural Gas Equivalent (mmcfe/d) | 755 | 376 | 154 |
| **Average Sales Prices:** | | | |
| Natural gas ($/mcf) | $ 2.93 | $ 2.39 | $ 2.62 |
| Oil ($/bbl) | $ 44.71 | $ 33.19 | $ 36.60 |
| NGL ($/bbl) | $ 23.45 | $ 14.23 | $ 12.20 |
| Natural Gas Equivalent ($/mcfe) | $ 3.25 | $ 2.67 | $ 3.17 |
| Settlements of commodity derivatives ($/mcfe) | 0.08 | 0.03 | 0.02 |
| Average sales price, after effects of settled derivatives ($/mcfe) | $ 3.33 | $ 2.70 | $ 3.19 |
| **Operating Expenses ($/mcfe):** | | | |
| Lease operating expenses | $ 0.13 | $ 0.18 | $ 0.38 |
| Gathering, processing and transportation expenses | $ 1.24 | $ 1.36 | $ 1.55 |
| Production and ad valorem taxes | $ 0.05 | $ 0.06 | $ 0.04 |
| General and administrative expenses, including related party | $ 0.17 | $ 0.28 | $ 1.28 |
| Natural gas and oil depreciation, depletion and amortization | $ 1.11 | $ 1.67 | $ 2.38 |
| Depreciation and amortization of other assets | $ 0.01 | $ 0.01 | $ 0.01 |

*General*. For the year ended December 31, 2017, we had a net loss of $28.7 million on total revenues of $1.1 billion. This compares to net loss of $360.6 million on total revenues of $280.7 million for 2016 and a net loss of $640.0 million on total revenues of $175.9 million for the year ended December 31, 2015. The net loss in 2017 was primarily driven by the $114.1 million loss related to the debt transactions in April 2017, which was largely offset by an increase in sales of natural gas, oil and NGL and unrealized commodity derivative gains. The net loss in 2016 was primarily driven by unrealized commodity derivative losses and exploration expenses while the net loss in 2015 was primarily driven by a loss on divestiture of natural gas and oil properties, litigation settlement expense and higher interest expense.

*Natural Gas Sales.* During 2017, natural gas sales were $706.9 million compared to $262.8 million in 2016 and $100.3 million in 2015. In 2017, we sold 241.0 bcf of natural gas at a weighted average price $2.93 per mcf (excluding the effect of derivatives), compared to 109.7 bcf sold in 2016 at a weighted average price of $2.39 per mcf (excluding the effect of derivatives) and 38.4 bcf sold in 2015 at a weighted average price of $2.62 per mcf (excluding the effect of derivatives). The $444.1 million increase in natural gas sales (excluding the effect of derivatives) in 2017 compared to 2016 was driven by a 120% increase in natural gas production, as well as a 23% increase in average sales prices received for natural gas. The $162.5 million increase in natural gas sales (excluding the effect of derivatives) from 2015 to 2016 was driven by a 186% increase in natural gas production which more than offset the 9% decrease in natural gas prices from 2015.

Gains and losses from our natural gas derivatives resulted in a net increase in natural gas revenues of $213.0 million in 2017 and a net decrease in natural gas revenues of $79.9 million in 2016 and $2.0 million in 2015, respectively.

A change in natural gas prices has a significant impact on our sales and cash flows. Assuming our 2017 production levels remained constant and without considering the effect of derivatives, an increase or decrease of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in sales and cash flows of approximately $24.1 million for 2017.

*Oil Sales.* During 2017, oil sales were $111.4 million compared to $67.6 million in 2016 and $62.5 million in 2015. In 2017, we sold 2,492 mbbls of oil at a weighted average price of $44.71 per bbl (excluding the effect of derivatives), compared to 2,035 mbbls sold in 2016 at a weighted average price of $33.19 per bbl (excluding the effect of derivatives) and 1,706 mbbls sold in 2015 at a weighted average price of $36.60 per bbl (excluding the effect of derivatives). The $43.8 million increase in oil sales (excluding the effect of derivatives) for 2017 compared to 2016 was driven by a 22% increase in oil production, as well as a 35% increase in average sales prices received for oil. The $5.1 million increase in oil sales (excluding the effect of derivatives) from 2015 to 2016 was driven by a 19% increase in oil production, which more than offset the 9% decrease in oil prices from 2015 to 2016.

Losses from our oil derivatives resulted in a net decrease in oil revenues of $1.0 million for 2017 and $6.6 million for 2016.

A change in oil prices has a direct impact on our sales and cash flows. Assuming our 2017 production levels remained constant and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would have resulted in an increase or decrease in sales and cash flows of approximately $2.5 million for 2017.

*NGL Sales.* During 2017, NGL sales were $77.1 million compared to $36.8 million in 2016 and $15.1 million in 2015. In 2017, we sold 3,286 mbbls of NGL at a weighted average price of $23.45 per bbl, compared to 2,588 mbbls sold in 2016 at a weighted average prices of $14.23 per bbl and 1,242 mbbls sold in 2015 at a weighted average price of $12.20 per bbl. The $40.3 million increase in NGL sales for 2017 compared to 2016 was driven by a 27% increase in NGL production, as well as a 65% increase in average sales prices received for NGL. The $21.7 million increase in NGL sales from 2015 to 2016 was driven by a 108% increase in NGL production, as well as a 17% increase in average sales prices received for NGL from 2015 to 2016.

A change in NGL prices has a direct impact on our sales and cash flows. Assuming our 2017 production levels remained constant, an increase or decrease of $1.00 per barrel of NGL sold would have resulted in an increase or decrease in sales and cash flows of approximately $3.3 million for 2017.

*Lease Operating Expenses*. Lease operating expenses were $35.3 million in 2017 compared to $24.1 million in 2016 and $21.1 million in 2015. On a per unit basis, lease operating expenses were $0.13 per mcfe in 2017 compared to $0.18 per mcfe in 2016 and $0.38 per mcfe in 2015. The per unit decreases in 2017 and 2016 were primarily the result of operating efficiencies, including implementation of preventative maintenance programs and improvements in our well management, facility construction and artificial lift techniques.

*Gathering, Processing and Transportation Expenses.* Gathering, processing and transportation expenses were $341.8 million in 2017 compared to $186.3 million in 2016 and $87.0 million in 2015. On a unit-of-production basis, gathering, processing and transportation expenses were $1.24 per mcfe in 2017 compared to $1.36 per mcfe in 2016 and $1.55 in 2015. The per unit decreases in 2017 and 2016 were due to increased annual production, which reduced expenses related to unused firm transportation.

*Production and Ad Valorem Taxes*. Production and ad valorem taxes were $14.1 million in 2017 compared to $7.6 million in 2016 and $2.5 million in 2015. Production taxes increased each year and were $8.1 million, $4.0 million and $1.5 million in 2017, 2016 and 2015, respectively. Production taxes are calculated using volume based formulas that produce higher absolute costs as production increases. On a unit-of-production basis, production taxes were $0.03 per mcfe in 2017, 2016 and 2015. Ad valorem taxes were $6.0 million, $3.6 million and $1.0 million in 2017, 2016 and 2015, respectively. Ad valorem taxes are assessed annually based on wells producing at the end of each year. The amount of tax is based on an appraised value of each well including various factors such as historical production at a well level, state decline curves and prices set by the state. The increase in ad valorem taxes from 2015 to 2016 and 2016 to 2017 was the result of the significant increase in the number of our producing wells from year to year.

*Exploration Expenses.* Exploration expenses for 2017 were $186.2 million compared to $270.0 million in 2016 and $85.4 million in 2015. We impaired $183.9 million of individually insignificant unproved natural gas and oil properties in 2017 compared to $252.8 million in 2016 and $70.0 million in 2015 associated with expected lease expirations. As we continue to review our acreage position and high grade our drilling inventory focusing on our core type curve areas, additional leasehold impairments and abandonment may be recorded. We also had rig standby or other charges of $11.9 million and $12.9 million for 2016 and 2015, respectively.

*General and Administrative Expenses, Including Related Party*. General and administrative expenses, including related party expenses, were $46.3 million in 2017, $39.1 million in 2016 and $71.6 million in 2015. On a unit-of-production basis, general and administrative expenses, including related party expenses, were $0.17 per mcfe in 2017 compared to $0.28 per mcfe in 2016 and $1.28 in 2015. The combined per unit expense decrease from 2016 to 2017 was primarily due to increased production in 2017. The absolute and per unit decrease from 2015 to 2016 was primarily due to reduced overhead as a result of the termination of a prior management service agreement in late 2015 and increased production in 2016. See Note 7, *Management Services Agreement*, of the notes to our consolidated financial statements included in this report for further discussion.

*Litigation Settlement (Benefit) Expense.* In 2015, we recognized litigation settlement expense of $93.0 million related to the lawsuit and settlement with Chesapeake Energy Corporation. The estimate consisted of $82.0 million for assignment of certain acreage and an $11.0 million accrual for contingent cash payments. In 2016, we recognized a $4.1 million decrease to the estimated settlement accrual.

*Natural Gas and Oil Depreciation, Depletion and Amortization*. Depreciation, depletion and amortization of natural gas and oil properties was $305.6 million, $229.0 million and $133.4 million for 2017, 2016 and 2015, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves, was $1.11 per mcfe in 2017 compared to $1.67 per mcfe in 2016 and $2.38 per mcfe in 2015. The per unit decrease from 2015 to 2016 and from 2016 to 2017 was the result of an increase in total proved reserves.

*Depreciation and Amortization of Other Assets*. Depreciation and amortization of other assets was $1.9 million in 2017 and 2016 compared to $0.7 million in 2015. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. Our other property and equipment consist mainly of field offices and other corporate assets.

*Impairment of Other Property and Equipment.* In 2016, we recorded a $2.2 million impairment associated with pipeline and gathering assets determined to no longer be in service and deemed obsolete.

*Loss on Divestiture of Natural Gas and Oil Properties.* In 2015, we sold certain assets and assigned certain pipeline transportation commitments to an unaffiliated buyer for an adjusted purchase price of approximately $405.0 million, resulting in a loss on divestiture of $205.6 million. The assets sold included approximately 35,000 net acres, consisting of unproved leasehold and producing and non-producing natural gas and oil properties located in the Utica Shale in Ohio, and a gas gathering system.

*Interest Expense.* Interest expense was $69.1 million in 2017 compared to $88.2 million in 2016 and $286.9 million in 2015, detailed as follows along with weighted average borrowings:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | ($ in thousands) | | |
| Interest expense on Senior Notes | $ 110,448 | $ — | $ — |
| Interest expense on Second Lien Term Loans | 37,502 | 162,410 | 145,498 |
| Interest expense on Convertible Notes | 3,552 | 10,754 | 29,601 |
| Interest expense on Credit Facilities | 14,908 | 72 | 1,931 |
| Interest expense on Junior Lien Debt | — | 94,912 | 47,049 |
| Interest expense on pipeline commitments | 3,293 | 4,209 | 968 |
| Amortization of debt discount and issuance costs | 21,632 | 39,452 | 97,330 |
| Capitalized interest | (122,273) | (223,650) | (35,524) |
| Total interest expense, net | $ 69,062 | $ 88,159 | $ 286,853 |
| | | | |
| Weighted Average Senior Notes borrowings | $ 1,109,589 | $ — | $ — |
| Weighted Average Second Lien Term Loans borrowings | $ 335,822 | $ 1,280,805 | $ 1,149,291 |
| Weighted Average Convertible Notes borrowings | $ 69,358 | $ 279,382 | $ 847,752 |
| Weighted Average Junior Lien borrowings | $ — | $ 587,459 | $ 277,632 |
| Weighted Average Credit Facilities borrowings | $ — | $ — | $ 41,871 |

The decrease in interest expense and amortization of debt discounts and issuance costs in 2017 compared to 2016 was primarily due to a decrease in interest expense associated with the Second Lien Term Loans as a result of the retirement of all of the outstanding $1.290 billion in principal in April 2017, the repurchase and retirement of all of the $789.3 million of outstanding principal associated with the junior lien debt and accrued and unpaid interest in November 2016, as well as the redemption of Convertible Notes in April 2016. This was partially offset by an increase in interest expense associated with the issuance of the 2022 Notes and 2017 Credit Facility in April 2017 and a reduction in capitalized interest as a result of a lower weighted average interest rate.

The decrease in interest expense in 2016 compared to 2015 was primarily due to capitalized interest of $223.7 million as a result of increased activity related to certain of our unproved properties. Additionally, amortization of debt discounts and issuance costs decreased from 2015 to 2016 as a result of the retirement of $661.9 million in principal of the Convertible Notes in February 2016.

*Acquisition Obligation Accretion Expense.* Acquisition obligation accretion expense was $4.3 million in 2017 compared to $10.1 million in 2016 and $17.1 million in 2015. Pursuant to a joint venture participation agreement, this obligation relates to the carried interest from certain asset acquisitions that require us to pay the seller's retained share of development costs for certain wells and other development operations that occur within an AMI as defined in the agreement. This obligation has been discounted using an 11% discount rate for the years ended December 31, 2017, 2016 and 2015, to reflect the imputation of interest. See Note 8, *Joint Venture Commitments*, of the notes to our consolidated financial statements for more details of this commitment.

*Change in Fair Value of Embedded Derivative.* The change in fair value of the embedded derivative in the Convertible Notes resulted in a loss of $19.3 million in 2017 compared to a gain of $3.6 million in 2016 and a gain of $211.6 million in 2015. In general, increases in the fair value of the associated debt, the probability of early exit, expected volatility, remaining time to maturity and the credit spread between the Convertible Notes and the risk-free rate would increase the value of the embedded derivative liability and result in a loss. Alternatively, decreases in these factors, including a decrease in the outstanding principal amount of Convertible Notes, would decrease the value of the embedded derivative liability.

*(Losses) Gains on Purchases or Exchanges of Debt.* We recognized a loss on purchases or exchanges of debt of $114.1 million in 2017 related to the repayment and retirement of the Second Lien Term Loans and the retirement of the 2016 Credit Facility in April 2017. In 2016, we recognized a gain on purchases or exchanges of debt of $207.5 million primarily in connection with the Exchange Offer and subsequent redemption of the Convertible Notes in February and April 2016, respectively. In 2015, we recognized a loss on purchases or exchanges of debt of $25.8 million primarily in connection with the retirement of $277.3 million of the Convertible Notes and the retirement of our 2015 Credit Facility in June 2015.

**Quantitative and Qualitative Disclosure 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 risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, oil and NGL prices, customer credit 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 exposures.

*Commodity Demand and Price Risk*

Our primary market risk exposure is in the prices we receive for our natural gas, oil and NGL production. Approximately 92% of our December 31, 2017 proved reserves are natural gas, and therefore, changes in realized natural gas pricing will affect us more than changes in realized oil or NGL pricing. Realized pricing is primarily driven by spot regional market prices applicable to our natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production is volatile and unpredictable, and we expect this volatility to continue in the future. The prices we expect to receive for our natural gas, oil and NGL production will depend on many factors outside of our control, including the supply of, and demand for, natural gas, oil and NGL, the level of economic activity in the United States and globally, and the performance of specific industries and volatility of natural gas, oil and NGL prices at various delivery points. We expect that a decrease in economic activity, in the United States and elsewhere, would adversely affect demand for the natural gas, oil and NGL that we expect to produce. During 2017, the Henry Hub spot market price of natural gas ranged from $2.44 to $3.65 per mmbtu and the West Texas Intermediate oil prices ranged from $42.53 to $60.42 per bbl.

To mitigate our exposure to adverse commodity price changes, we have periodically entered into commodity derivative instruments. We do not enter into commodity derivative instruments for speculative or trading purposes. Under the terms of a swap, we receive a fixed price for our natural gas or oil production and pay a variable market price to the counterparty. Options are used to establish a floor price (put), a ceiling price (call) or a floor and a ceiling price (collar) for expected future production. The sold call establishes the maximum price that we will receive for contracted commodity volumes. The purchased put establishes the minimum price that we will receive for the contracted volumes. Given that our natural gas is sold at various delivery points that at times may have material spreads or volatility relative to NYMEX, basis swaps may be periodically used to fix or float the differential between product prices at one market location versus another.

At December 31, 2017, we had a net asset derivative position of $94.4 million. The following table sets forth the volumes per day associated with our outstanding natural gas derivative instruments as of December 31, 2017 and the contracted weighted average natural gas prices:

| | | Weighted Average Price | | |
|---|---|---|---|---|
| | Volume (mmbtu/d) | Swap fixed price | Sold call strike price | Purchased put strike price |
| | | | ($/mmbtu) | |
| **Natural gas:** | | | | |
| **Swaps:** | | | | |
| 2018 | 937,000 | $ 3.02 | | |
| 2019 | 1,336,000 | $ 2.88 | | |
| 2020 | 138,000 | $ 2.82 | | |
| **Basis Swaps:** | | | | |
| 2018 | 197,000 | $ (0.20) | | |
| 2019 | 170,000 | $ (0.20) | | |
| **Collars:** | | | | |
| 2018 | 134,000 | | $ 3.27 | $ 3.00 |
| **Call options:** | | | | |
| 2018 | 50,000 | | $ 3.25 | |

The following table sets forth the volumes per day associated with our outstanding oil derivative instruments as of December 31, 2017 and the contracted weighted average oil prices:

| | Average Volume (bbl/d) | Weighted Average NYMEX ($/bbl) |
|---|---|---|
| **Oil :** | | |
| **Swaps:** | | |
| 2018 | 3,900 | $ 53.47 |
| 2019 | 4,000 | $ 52.64 |

As of December 31, 2017, a $0.10 increase or decrease in natural gas prices would have decreased or increased the fair value of our natural gas derivatives by approximately $75.2 million, respectively. As of December 31, 2017, a $1.00 increase or decrease in oil prices would have decreased or increased the fair value of our oil derivatives by approximately $2.8 million, respectively. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual revenue received from the sale of our production covered by the derivative instrument.

*Counterparty Credit Risk*

Our derivative instruments expose us to counterparty credit risk. Credit risk is the risk of loss from counterparties not performing under the terms of the derivative instrument. Adverse moves within the financial or commodity markets could negatively impact our counterparties' ability to fulfill obligations to us. To minimize such risk, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty. Also, we only enter into derivative contracts with counterparties that are creditworthy. The creditworthiness of our counterparties is subject to periodic review.

*Customer Credit Risk*

We are subject to credit risk resulting from the concentration of our natural gas, oil and NGL receivables. The following table provides the concentration of sales to individual purchasers that constitute 10% or more of our revenues, before the effects of derivatives:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| Tenaska Marketing Ventures | 25% | 47% | 37% |
| Sequent Energy Management, L.P. | 24% | — | — |
| Marathon Petroleum Company, L.P. | — | 16% | 36% |

If our largest customers decided to stop purchasing natural gas or oil from us, our revenues could decline and our operating results and financial condition could be harmed. Although a substantial portion of our production is purchased by these major customers, we do not believe the loss of any single purchaser would materially impact our operating results, as natural gas, oil and NGL are fungible products with well-established markets and numerous purchasers in our operating region.

We also have joint interest receivables, which arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells, nor can we require these entities to post collateral to us if these entities are judged to have sub-standard credit. We historically have not incurred losses on our joint interest receivables.

*Interest Rate Risk*

At December 31, 2017, the Convertible Notes bore interest at an escalating rate of 5.5% and the 2022 Notes bore interest at a fixed rate of 10.0%. The 2017 Credit Facility incurred participation fees associated with outstanding letters of credit at a variable tiered rate based on facility usage plus the 1-month LIBOR exposing us to interest rate risk. A 1.0% increase in the LIBOR for the year ended December 31, 2017 would have resulted in an estimated $2.9 million increase in interest expense on the 2017 Credit Facility, which was established in April 2017. We had no outstanding interest rate derivatives at December 31, 2017.

*Inflation*

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

## Report of Independent Registered Public Accounting Firm

To the Board of Managers and Member of Ascent Resources Utica Holdings, LLC

### *Opinion on the Financial Statements*

We have audited the accompanying consolidated balance sheets of Ascent Resources Utica Holdings, LLC and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, of member's equity and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

### *Basis for Opinion*

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the relevant ethical requirements relating to our audit, which include standards of the American Institute of Certified Public Accountants (AICPA) *Code of Professional Conduct*.

We conducted our audits of these consolidated financial statements in accordance with the auditing standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

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

PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
March 7, 2018

We have served as the Company's auditor since 2015.

*PricewaterhouseCoopers LLP, 211 N. Robinson Ave., Ste 1400, Oklahoma City, OK 73102*
*T: (405) 290 7200, F: (405) 290 7201, www.pwc.com*

## ASCENT RESOURCES UTICA HOLDINGS, LLC
## CONSOLIDATED BALANCE SHEETS

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| | ($ in thousands) | |
| **Current Assets:** | | |
| Cash and cash equivalents | $ 119,215 | $ 268,493 |
| Accounts receivable – natural gas, oil and NGL sales | 146,788 | 75,350 |
| Accounts receivable – joint interest and other | 40,934 | 3,224 |
| Short-term derivative assets | 76,439 | — |
| Other current assets | 3,057 | 1,067 |
| Total Current Assets | 386,433 | 348,134 |
| **Property and Equipment:** | | |
| Natural gas and oil properties, based on successful efforts accounting | 4,441,612 | 3,638,619 |
| Other property and equipment | 19,625 | 19,508 |
| Less: accumulated depreciation, depletion and amortization | (678,274) | (370,955) |
| Property and Equipment, net | 3,782,963 | 3,287,172 |
| **Other Assets:** | | |
| Deposits on pipeline transportation | — | 151,193 |
| Long-term derivative assets | 31,441 | — |
| Other long-term assets | 13,032 | 6,959 |
| **Total Assets** | $ 4,213,869 | $ 3,793,458 |
| **Current Liabilities:** | | |
| Accounts payable | $ 75,665 | $ 37,916 |
| Revenue payable | 63,211 | 34,167 |
| Accrued interest | 42,438 | 11,829 |
| Short-term derivative liabilities | 8,660 | 74,489 |
| Acquisition obligation | 60,083 | 47,121 |
| Other current liabilities | 200,100 | 114,435 |
| Total Current Liabilities | 450,157 | 319,957 |
| **Long-Term Liabilities:** | | |
| Long-term debt, net | 1,564,774 | 1,325,325 |
| Long-term derivative liabilities | 4,869 | 19,414 |
| Acquisition obligation | — | 50,824 |
| Other long-term liabilities | 11,569 | 10,755 |
| Total Long-Term Liabilities | 1,581,212 | 1,406,318 |
| Commitments and contingencies (Note 8) | | |
| **Member's Equity** | 2,182,500 | 2,067,183 |
| **Total Liabilities and Member's Equity** | $ 4,213,869 | $ 3,793,458 |

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

## ASCENT RESOURCES UTICA HOLDINGS, LLC
## CONSOLIDATED STATEMENTS OF OPERATIONS

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| **Revenues:** | | | |
| Natural gas | $ 706,866 | $ 262,765 | $ 100,311 |
| Oil | 111,441 | 67,551 | 62,461 |
| NGL | 77,054 | 36,833 | 15,146 |
| Commodity derivative gain (loss) | 212,046 | (86,434) | (2,005) |
| Total Revenues | 1,107,407 | 280,715 | 175,913 |
| **Operating Expenses:** | | | |
| Lease operating expenses | 35,259 | 24,061 | 21,119 |
| Gathering, processing and transportation expenses | 341,765 | 186,300 | 86,973 |
| Production and ad valorem taxes | 14,050 | 7,623 | 2,504 |
| Exploration expenses | 186,152 | 269,982 | 85,394 |
| General and administrative expenses | 5,331 | 6,686 | 15,875 |
| General and administrative expenses – related party | 40,994 | 32,460 | 55,729 |
| Litigation settlement (benefit) expense | — | (4,147) | 92,974 |
| Natural gas and oil depreciation, depletion and amortization | 305,573 | 229,038 | 133,410 |
| Depreciation and amortization of other assets | 1,905 | 1,864 | 660 |
| Impairment of other property and equipment | — | 2,222 | — |
| Loss on divestiture of natural gas and oil properties | — | — | 205,638 |
| Total Operating Expenses | 931,029 | 756,089 | 700,276 |
| **Income (Loss) From Operations** | 176,378 | (475,374) | (524,363) |
| **Other (Expense) Income:** | | | |
| Interest expense, net | (69,062) | (88,159) | (286,853) |
| Acquisition obligation accretion expense | (4,290) | (10,108) | (17,118) |
| Change in fair value of embedded derivative | (19,261) | 3,616 | 211,593 |
| (Losses) gains on purchases or exchanges of debt | (114,052) | 207,470 | (25,831) |
| Other income | 1,572 | 2,001 | 2,596 |
| Total Other (Expense) Income | (205,093) | 114,820 | (115,613) |
| **Net Loss** | $ (28,715) | $ (360,554) | $ (639,976) |

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

## ASCENT RESOURCES UTICA HOLDINGS, LLC
## CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| | | **($ in thousands)** | |
| **Balance, beginning of period** | $ 2,067,183 | $ 588,568 | $ 848,833 |
| Contributions from Member | 132,000 | 1,839,889 | 385,000 |
| Contribution of debt held by Member | 11,942 | — | — |
| Purchase of debt by Member | — | (745) | — |
| Incentive unit compensation | 90 | 25 | (5,289) |
| Net loss | (28,715) | (360,554) | (639,976) |
| **Balance, end of period** | $ 2,182,500 | $ 2,067,183 | $ 588,568 |

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

## ASCENT RESOURCES UTICA HOLDINGS, LLC
## CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | ($ in thousands) | | |
| **Cash Flows from Operating Activities:** | | | |
| Net loss | $ (28,715) | $ (360,554) | $ (639,976) |
| Adjustments to reconcile net loss to net cash provided by (used in) operating activities: | | | |
| Depreciation, depletion and amortization | 307,478 | 230,902 | 134,070 |
| Impairment of other property and equipment | — | 2,222 | — |
| Change in fair value of commodity derivatives | (188,254) | 90,831 | 3,072 |
| Impairment of unproved natural gas and oil properties | 183,885 | 252,845 | 69,969 |
| Non-cash interest expense | 23,714 | 84,706 | 194,645 |
| Acquisition obligation accretion expense | 4,290 | 10,108 | 17,118 |
| Change in fair value of embedded derivative | 19,261 | (3,616) | (211,593) |
| Losses (gains) on purchases or exchanges of debt | 114,052 | (207,470) | 25,831 |
| Litigation settlement (benefit) expense | — | (4,147) | 92,974 |
| Loss on divestiture of natural gas and oil properties | — | — | 205,638 |
| Other | 2,766 | 733 | (3,072) |
| Changes in operating assets and liabilities: | | | |
| Increase in accounts receivable and other assets | (95,882) | (32,658) | (9,261) |
| Increase (decrease) in accounts payable, liabilities and other | 142,849 | 28,890 | (39,369) |
| **Net Cash Provided by (Used in) Operating Activities** | 485,444 | 92,792 | (159,954) |
| **Cash Flows from Investing Activities:** | | | |
| Drilling and completion costs | (653,942) | (268,082) | (760,435) |
| Acquisitions of natural gas and oil properties | (429,890) | (428,301) | (217,677) |
| Proceeds from divestitures of natural gas and oil properties | 79,329 | 16,664 | 385,964 |
| Proceeds from sale of other property and equipment | 28 | — | 15,882 |
| Reductions in (additions to) deposits on pipeline transportation | 151,193 | (41,811) | 13,705 |
| Additions to other property and equipment | (285) | (715) | (13,689) |
| Additions to other long-term assets | — | — | (21,041) |
| **Net Cash Used in Investing Activities** | (853,567) | (722,245) | (597,291) |
| **Cash Flows from Financing Activities:** | | | |
| Proceeds from issuance of long-term debt, net | 1,466,250 | — | 922,210 |
| Repayment of debt | (1,290,264) | (464,649) | (477,250) |
| Cash paid for debt issuance costs | (18,142) | (15,474) | (43,657) |
| Cash paid for debt prepayment costs | (70,999) | (667) | — |
| Repayment of note payable to third party | — | (37,170) | — |
| Contributions from Member | 132,000 | 1,331,719 | 385,000 |
| **Net Cash Provided by Financing Activities** | 218,845 | 813,759 | 786,303 |
| **Net (Decrease) Increase in Cash and Cash Equivalents** | (149,278) | 184,306 | 29,058 |
| **Cash and Cash Equivalents, Beginning of Period** | 268,493 | 84,187 | 55,129 |
| **Cash and Cash Equivalents, End of Period** | $ 119,215 | $ 268,493 | $ 84,187 |

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

## ASCENT RESOURCES UTICA HOLDINGS, LLC
## CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| **Supplemental disclosures of cash flow information:** | | | |
| Interest paid, net of capitalized interest and interest paid in kind | $ 12,901 | $ — | $ 109,145 |
| **Supplemental disclosures of significant non-cash investing and financing activities:** | | | |
| Non-cash consideration from divestiture of natural gas and oil properties | $ 22,056 | $ — | $ — |
| Increase (decrease) in accrued capital expenditures | $ 22,224 | $ (24,058) | $ (47,985) |
| Contributions from Member - non-cash issuance of Parent equity | $ — | $ 508,170 | $ — |
| Contribution of debt held by Member | $ 11,942 | $ — | $ — |
| Natural gas and oil property acquired with note payable | $ — | $ — | $ 37,170 |

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

## 1. Basis of Presentation and Significant Accounting Policies

*Basis of Presentation and Consolidation*

Ascent Resources Utica Holdings, LLC (ARUH), together with its wholly-owned subsidiaries (collectively, "the Company"), is engaged in the acquisition, exploration, development, production and operation of natural gas and oil properties located in the Utica Shale in Ohio.

The accompanying consolidated financial statements and notes of the Company have been prepared in accordance with United States generally accepted accounting principles (US GAAP) and include the accounts of the Company and its wholly-owned subsidiaries. ARUH is a wholly-owned subsidiary of Ascent Resources Operating, LLC (the Member), which is an indirect, wholly-owned subsidiary of Ascent Resources, LLC (the Parent). The Parent is majority owned by investment funds controlled by The Energy & Minerals Group (EMG) and First Reserve Corporation (First Reserve). Intercompany accounts and balances have been eliminated.

*Business Segment Information*

The Company evaluated how it is organized and managed and has identified only one operating segment, which is the exploration, development and production of natural gas, oil, and natural gas liquids (NGL) in the United States. Operating segments are defined as components of an enterprise that engage in business activities from which it may earn revenues and incur expenses for which discrete operational financial information is available and this information is regularly reviewed by the chief operating decision maker to make decisions about the allocation of resources and assessment of performance.

The Company has one reportable operating segment in the United States and a single company-wide management team that administers all properties as a whole rather than by distinct operating segments. The Company measures financial performance as a single enterprise and not on a geographical basis.

*Risks and Uncertainties*

A substantial or extended decline in natural gas, oil and NGL prices could have a material impact on the Company's financial position, results of operations, cash flows and quantities of natural gas, oil and NGL reserves that may be economically produced. Furthermore, in a low commodity price environment the Company's ability to generate positive operating cash flows, maintain its natural gas, oil and NGL production and reserves, sell assets, or take any other action to improve its liquidity is subject to risks and uncertainties that exist in its industry, some of which the Company may not be able to anticipate at this time or control. Other risks and uncertainties that could affect the Company include, but are not limited to, counterparty credit risk, access to capital markets, regulatory risk and its ability to meet financial ratios and other covenants in its debt agreements.

*Accounting Estimates*

The preparation of consolidated financial statements in accordance with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures in the consolidated financial statements. Actual amounts could differ from these estimates.

Estimates of natural gas, oil and NGL reserves and their values, future production rates and future costs and expenses are the most significant of the Company's estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, commodity prices, operating costs and other factors. These revisions could materially affect the Company's financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in natural gas, oil or NGL prices could result in actual results differing significantly from the Company's estimates.

*Concentration of Credit Risk*

The Company is subject to credit risk resulting from the concentration of its natural gas, oil and NGL receivables. The following table provides the concentration of sales to individual purchasers that constitute 10% or more of the Company's revenues, before the effects of derivatives, for the periods indicated:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Tenaska Marketing Ventures | 25% | 47% | 37% |
| Sequent Energy Management, L.P. | 24% | — | — |
| Marathon Petroleum Company, L.P. | — | 16% | 36% |

The Company does not believe the loss of any single purchaser would materially impact its operating results, as natural gas, oil and NGL are fungible products with well-established markets and numerous purchasers in the Company's operating region.

*Cash and Cash Equivalents*

The Company considers investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents. The Company maintains its cash in accounts that may not be federally insured beyond certain limits; however, the Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts.

*Accounts Receivable*

The Company sells natural gas, oil and NGL to various counterparties and participates with other companies in the drilling, completion and operation of natural gas and oil wells. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts after all attempts to collect the balance are exhausted. Accounts receivable at December 31, 2017 and 2016 were $187.7 million and $78.6 million, respectively, and consist primarily of accrued natural gas, oil and NGL revenue receivables and receivables from joint interest billings to owners of properties the Company operates. All accounts receivable are considered to be fully collectible; therefore, no allowance for doubtful accounts is recorded in the consolidated financial statements.

*Natural Gas and Oil Properties*

The Company uses the successful efforts method of accounting for natural gas and oil properties, whereby costs incurred to acquire interests in properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Exploration costs, such as most geological and geophysical costs, are expensed as incurred. Under the successful efforts method of accounting, the Company capitalizes exploratory drilling costs, including capitalized interest, in the balance sheet pending determination of whether a well has found proved reserves in economically producible quantities. If proved reserves are found by an exploratory well, the associated capitalized costs become part of proved natural gas and oil properties; however, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value, to exploration expense. Acquisition costs of unproved properties are transferred to proved properties to the extent the costs are associated with successful exploration activities.

Proved natural gas and oil properties are reviewed for impairment whenever events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The estimated undiscounted future cash flows expected are compared to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the properties is reduced to its estimated fair value (typically determined using discounted future cash flows). No impairment of proved natural gas and oil properties was recorded for the years ended December 31, 2017, 2016 or 2015. The Company cannot predict whether impairment charges may be required in the future as commodity prices of natural gas, oil and NGL have a significant impact on determining future impairments.

Non-producing natural gas and oil properties primarily consist of undeveloped leasehold costs. Individually significant non-producing properties, if any, are assessed for impairment on a property-by-property basis and, if the assessment indicates an impairment, a loss is recognized. For individually insignificant non-producing properties, impairment losses are recognized by amortizing to exploration expense the portion of the properties' costs that management estimates will not be transferred to proved properties over the remaining lease term. The Company's impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms and potential shifts in business strategy employed by management. For the years ended December 31, 2017, 2016 and 2015, the Company recorded impairments of \$183.9 million, \$252.8 million and \$70.0 million, respectively, to exploration expense related to individually insignificant non-producing natural gas and oil properties.

*Natural Gas and Oil Depreciation, Depletion and Amortization*

Natural gas and oil depreciation, depletion and amortization (DD&A) of capitalized drilling and completion costs of producing natural gas and oil properties is computed using the unit-of-production method, based on total estimated proved developed natural gas, oil and NGL reserves. Costs of acquiring proved properties, including leasehold acquisition costs and capitalized interest transferred from unproved properties, are depleted using the unit-of-production method based on total estimated proved natural gas, oil and NGL reserves.

*Other Property and Equipment*

Other property and equipment is recorded at cost. Upon retirement or disposition of assets, the cost and related accumulated depreciation are removed from the balance sheet with the resulting gain or loss, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the related assets generally ranging from three to seven years. The field office location is depreciated using the straight-line method over the estimated useful life of 39 years. Depreciation expense for other property and equipment was \$1.9 million for the years ended December 31, 2017 and 2016 and \$0.7 million for the year ended December 31, 2015. During the year ended December 31, 2016, the Company recorded a \$2.2 million impairment associated with pipeline and gathering assets determined to no longer be in service and deemed obsolete.

*Asset Retirement Obligations*

The Company recognizes liabilities for retirement obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the assets. The Company recognizes the fair value of a retirement obligation in the period in which the obligation is incurred. For natural gas and oil properties, this is the period in which a natural gas or oil well is acquired or drilled. The liability is then accreted to its present value each period, until it is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of the Company's natural gas and oil properties and expensed through depletion of the asset. The accretion expense is recorded as a component of DD&A in the Company's consolidated statements of operations.

*Capitalized Interest*

The Company capitalizes interest on expenditures made in connection with exploration and development projects, which include developing and constructing assets that have not yet commenced production and investments in unproved oil and gas properties. Capitalized interest is determined by multiplying the Company's weighted average interest rate, based on the Company's outstanding borrowings, by the average amount of qualifying costs incurred. Capitalized interest is depreciated over the useful lives of the assets in the same manner as the depreciation of the underlying asset.

*Debt Issuance Costs*

Debt issuance costs associated with the Company's term debt have been presented as a reduction to long-term debt in the consolidated balance sheets. The Company amortizes debt issuance costs related to the Convertible Notes and 2022 Notes through the maturity date using the effective interest method. The amortization of debt issuance costs is recorded in interest expense in the consolidated statements of operations.

Debt issuance costs associated with the Company's credit facilities have been presented as other long-term assets in the consolidated balance sheets. The Company amortizes debt issuance costs related to credit facilities over the scheduled maturity period of the facility on a straight-line basis, which approximates the effective interest method. The amortization of debt issuance costs associated with the Company's credit facilities is recorded in interest expense in the consolidated statements of operations.

*Revenue Recognition*

Revenue from the sale of natural gas, oil and NGL is recognized when title passes, net of royalties due to third parties. The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has under-produced or over-produced its ownership percentage in a property. Under this method, a receivable or payable is recognized only to the extent an imbalance cannot be recouped from the reserves in the underlying properties. At December 31, 2017 and 2016, the Company had insignificant natural gas imbalances.

*Fair Value of Financial Instruments*

Certain financial instruments are reported at fair value on the consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments.

*Equity-Based Compensation*

In order to provide incentives to certain officers, employees, consultants and professionals of the Parent and certain of its affiliates, the Parent, and certain of its affiliates, established incentive compensation plans and granted incentive units to individuals for past and future performance of services to or for the benefit of the Company. These incentive units are intended to constitute profits interests.

To the extent the recipients of the incentive units are employees, the units are accounted for as liability-classified awards in accordance with ASC 718 *Stock Compensation* as the incentive units are settled in cash. Fair value of the employee incentive units is re-measured each reporting period until the awards are settled.

To the extent the recipients of the incentive units are non-employees, the units are accounted for as share-based payments to non-employees in accordance with ASC 505-50, *Equity Based Payments to Non-Employees*, classified as equity instruments. Fair value of the non-employee incentive units is re-measured each reporting period until the awards are vested.

Compensation expense for each period is based on the change (or a portion of the change, depending on the percentage of the requisite service that has been rendered at the reporting date) in the fair value of the instrument for each reporting period. A portion of the incentive unit expense recognized by the Parent under each plan is allocated to the Company each reporting period. The Company had expense of $2.6 million and $0.7 million associated with incentive units for the years ended December 31, 2017 and 2016 and $5.2 million of income for the year ended December 31, 2015, which is included on the consolidated statements of operations in general and administrative expenses - related party.

*Derivatives*

The Company periodically enters into commodity derivative instruments to secure attractive pricing and margins on its share of expected production, to reduce its exposure to fluctuations in future commodity prices and to protect its expected operating cash flow against significant market movements or volatility.

All commodity derivative instruments are recognized at their current fair value as either assets or liabilities in the consolidated balance sheets. Changes in the fair value of these commodity derivative instruments are recorded in earnings unless specific hedge accounting criteria are met. The Company has elected not to designate any of its commodity derivative instruments for hedge accounting treatment. By using commodity derivative instruments, the Company is exposed to credit risk associated with its hedge counterparties. To minimize such risk, the Company's derivative contracts are with multiple counterparties, reducing its exposure to any individual counterparty. Also, the Company only enters into derivative contracts with counterparties that are creditworthy. The creditworthiness of its counterparties is subject to periodic review.

Derivative instruments reflected as current in the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices or rates as of the respective balance sheet dates. Cash settlements of the Company's derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statements of cash flows. All of the Company's derivative instruments are subject to International Swaps and Derivatives Associations (ISDA) master netting arrangements by contract type (i.e., commodity, interest rate and cross currency contracts) which provide for the offsetting of asset and liability positions within each contract type, as well as related cash collateral if applicable, by counterparty. ISDA master agreements also provide for net settlement over the term of the contract and in the event of default or termination of the contract. The Company nets the value of its derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

The Company has established the fair value of its derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to the Company's counterparty values for reasonableness. The values the Company reports in its financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations and are also subject to the risk of the Company's non-performance. This non-performance risk is considered in the valuation of the Company's derivative instruments, but to date has not had a material impact on the values of its derivatives. See Note 5 for further discussion of the Company's derivative instruments.

*Income Taxes*

The Company is treated as a disregarded entity by the Parent for income tax purposes. The Parent is treated as a partnership for income tax purposes, with each partner being separately taxed on their share of income. As such, no income taxes are shown on the Company's consolidated financial statements.

*Adopted and Recently Issued Accounting Pronouncements*

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. The standard's core principle is that an entity shall recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. In August 2015, the FASB issued ASU 2015-14, which deferred the effective date of the new revenue standard by one year. This amendment is effective for periods beginning after December 15, 2017 for public business entities and December 15, 2018 for non-public entities, though the FASB has permitted entities to adopt one year earlier if they chose (i.e., the original effective date). The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the consolidated financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. In December 2016, the FASB issued ASU 2016-20 which updates narrow aspects of the guidance issued in ASU 2014-09. The Company is currently finalizing its evaluation of the impact of this ASU on its consolidated financial statements and working to identify any potential differences that would result from applying the requirements of the ASU to existing contracts and current accounting policies and practices. This evaluation includes the review of material revenue contracts. The Company has identified disclosure and control changes necessary for adoption. The Company expects to adopt the new standard using the modified retrospective approach for implementation.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*. The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Classification of leases as either a finance or operating lease will determine the recognition, measurement and presentation of expenses. This accounting standards update also requires certain quantitative and qualitative disclosures about leasing arrangements. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The amendments are effective for interim and annual reporting periods beginning after December 15, 2018 for public business entities and December 15, 2019 for non-public entities, with early adoption permitted. The Company is currently evaluating the impact of this ASU on its consolidated financial statements and disclosures. Based on our preliminary review, the Company expects to have leases with durations greater than twelve months on our balance sheet. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842), Land Easement Practical Expedient for Transition to Topic 842*. This ASU would permit an entity to not apply Topic 842 to land easements and rights-of-way that existed or expired before the effective date of Topic 842 and that were not previously assessed under Topic 840. An entity would continue to apply its current accounting policy for land easements that existed before the effective date of Topic 842. Once an entity adopts Topic 842, it would be applied prospectively to all new (or modified) land easements and rights-of way to determine whether the arrangement should be accounted for as a lease.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*. This guidance addresses eight specific cash flow issues. This amendment is effective for periods beginning after December 15, 2017 for public business entities and December 15, 2018 for non-public entities, with early adoption permitted, and should be applied retrospectively to all periods presented. The Company adopted this guidance in the fourth quarter of 2017. The primary effect from adoption is that all payments for debt prepayment or debt extinguishment costs, excluding accrued interest, are classified as cash outflows for financing activities. A retrospective change to the December 31, 2016 consolidated statement of cash flows as previously presented is required pursuant to this standard, which resulted in a decrease to gains on purchases or exchanges of debt in cash flows from operating activities and an increase to cash paid for debt prepayment costs in cash flows from financing activities of $0.7 million.

In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash*. This update is intended to reduce diversity in practice by adding or clarifying guidance on classification and presentation of changes in restricted cash on the statement of cash flows. This amendment is effective for annual and interim periods beginning after December 15, 2017 for public business entities and December 15, 2018 for non-public entities, with early adoption permitted, and should be applied retrospectively to all periods presented. The Company adopted this guidance in the fourth quarter of 2017 with no impact to its consolidated financial statements.

In January 2017, the FASB issued ASU 2017-01 - *Business Combinations (Topic 805): Clarifying the Definition of a Business*. This update clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This amendment is effective for annual and interim periods beginning after December 15, 2017 for public business entities and annual periods beginning after December 15, 2018 and interim periods within annual periods beginning after December 15, 2019 for non-public entities. Early adoption is permitted, and this guidance is applicable to business combinations completed after the adoption of the guidance. The Company adopted this guidance in the fourth quarter of 2017, which resulted in the Utica Acquisition (defined below) being evaluated based on the criteria in the guidance.

## 2. Acquisitions and Divestitures

In November 2017, the Company acquired and contemporaneously sold both producing and non-producing natural gas and oil properties located in the Utica Shale in Ohio in the following series of transactions:

- The Company acquired approximately 16,400 net acres, which included both producing and non-producing natural gas and oil properties (the Utica Acquisition) for a purchase price of $62.0 million, subject to customary closing adjustments. The Company funded the Utica Acquisition with funds from the Utica Divestiture described below. The Utica Acquisition primarily consisted of non-producing natural gas and oil properties and was accounted for as an asset acquisition. The Utica Acquisition includes contingent consideration if the price of oil is greater than certain pre-defined prices in 2018, 2019, and 2020. See Note 8, *Contingency*, for further discussion of the contingent liability. A portion of the acquired assets were divested as described below.
- The Company sold a partial interest in producing and non-producing natural gas and oil properties, which included certain properties acquired in the Utica Acquisition and other properties partially developed by us, for a sales price of $74.6 million, subject to customary closing adjustments (the Utica Divestiture). The proceeds were used to fund the Utica Acquisition and for general corporate purposes. As part of the Utica Divestiture, the Company entered into a development agreement whereby the buyer is required to pay 75.0% of the Company's development costs (carried costs) for the development of 34 wells in exchange for 58.5%

of the Company's working interest. The carried costs are subject to a ceiling of approximately 105.0% of the mutually agreed upon development costs, after which, the Company is required to pay 90.0% of all of its and the buyer's remaining development costs. As of December 31, 2017, the buyer had carried $4.4 million of the Company's associated development costs.

- In conjunction with the joint venture participation agreement related to an area of mutual interest (AMI) with one of the Company's joint venture partners, the Company sold 4,400 net acres, which included a partial interest in certain producing and non-producing natural gas and oil properties and 3,270 net acres, which were acquired in the Utica Acquisition. Additionally, the Company sold 1,130 net unproved acres within the AMI. The total sales price for this transaction was $21.8 million, subject to customary closing adjustments. The consideration for the sales price was a reduction to the Company's cash carry obligations to the joint venture partner. See Note 8, *Joint Venture Commitments*, for more details of this transaction.

In August 2017, Utica Minerals Development, LLC (UMD) and the Company acquired approximately 10,400 net acres of primarily unproved leasehold in the Utica Shale in Ohio (the Acquisition Properties) for a purchase price of $98.0 million, subject to customary closing adjustments. At closing, the Company received an undivided 25% interest in the Acquisition Properties for $33.4 million with UMD receiving the remaining undivided 75% interest in the Acquisition Properties. The Company funded this acquisition with $32.0 million that was contributed from the Member and cash on hand. The acquisition primarily consisted of non-producing natural gas and oil properties and was accounted for as an asset acquisition.

Pursuant to an agreement between the Company and UMD (the Earn-In Agreement), the Company can earn an additional undivided 25% interest in the Acquisition Properties from UMD by drilling and operating a designated set of wells on the Acquisition Properties and carrying 100% of UMD's drilling and completion costs (carried costs) of approximately $22.0 million. As of December 31, 2017, the remaining carried cost balance was approximately $20.8 million. Upon the Company's full payment of the UMD carried costs, each party will own an undivided 50% interest in the Acquisition Properties. In accordance with the Earn-In Agreement, the Company will have the right to pay the outstanding balance of the carry, and any prepayment penalty (if applicable), at any time prior to December 31, 2018 (the Term Date). Should the Company fail to satisfy the UMD carried costs by the Term Date, the Company will be required to forfeit and assign to UMD its rights and title in any interest earned by the Company pursuant to the Earn-In Agreement. See Note 7, *UMD Agreements*, for a discussion of a joint development agreement with UMD.

In June 2015, the Company sold certain assets and assigned certain pipeline transportation commitments for an adjusted sales price of approximately $405.0 million. The assets sold included approximately 35,000 net acres, consisting of unproved leasehold and producing and non-producing natural gas and oil properties located in the Utica Shale in Ohio, and a gas gathering system. The Company recognized an aggregate loss of $205.6 million on this divestiture.

## 3. Property and Equipment

Net property and equipment included the following:

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| | ($ in thousands) | |
| Proved natural gas and oil properties | $ 3,322,876 | $ 2,094,137 |
| Unproved natural gas and oil properties | 1,118,736 | 1,544,482 |
| Other property and equipment | 19,625 | 19,508 |
| Total Property and Equipment | 4,461,237 | 3,658,127 |
| Accumulated depreciation, depletion and amortization | (678,274) | (370,955) |
| Property and Equipment, net | $ 3,782,963 | $ 3,287,172 |

At December 31, 2017 and 2016, the Company did not have any capitalized well costs associated with exploratory wells that were pending determination of proved reserves.

The Company's asset retirement obligations relate to future plugging and abandonment costs on its natural gas and oil properties and are included in other long-term liabilities on the consolidated balance sheets. As of December 31, 2017 and 2016, the associated liabilities were $0.6 million and $0.1 million, respectively.

**4. Long-Term Debt**

The Company's long-term debt consisted of the following:

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| | ($ in thousands) | |
| Senior notes due 2022[a] | $ 1,500,000 | $ — |
| Second lien term loans due 2018[b] | — | 1,290,263 |
| Convertible notes due 2021[c] | 93,693 | 82,870 |
| Net unamortized debt issuance costs | (3,087) | (40,169) |
| Net unamortized debt discounts | (25,832) | (7,639) |
| Total Long-Term Debt, net | $ 1,564,774 | $ 1,325,325 |

(a) The interest rate was 10.0% as of December 31, 2017.
(b) The interest rate was 11.0% at the time of its retirement in April 2017 and as of December 31, 2016.
(c) The interest rate was 5.5% and 4.5% as of December 31, 2017 and December 31, 2016, respectively.

*Senior Notes*

In April 2017, the Company issued $1.5 billion in aggregate principal amount of senior unsecured notes (2022 Notes) in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The 2022 Notes are due on April 1, 2022, and interest is payable at an annual rate of 10.0% on April 1 and October 1 of each year, which commenced on October 1, 2017. Net proceeds to the Company were $1.466 billion. The proceeds were used to repay and retire all of the Company's outstanding second lien term loans (Second Lien Term Loans) and for general corporate purposes. The Company's obligations under the 2022 Notes are fully and unconditionally guaranteed, jointly and severally, by any current and future material subsidiaries of the Company. The Company's 2022 Notes are governed by an indenture containing covenants limiting, among other things, its ability to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into certain transactions with affiliates. The Company was in compliance with all applicable covenants under the indenture as of December 31, 2017.

At any time prior to April 1, 2020, the Company may redeem up to 35% of the aggregate principal amount of the 2022 Notes at a price equal to 110% of the principal amount, plus accrued and unpaid interest to, but excluding, the redemption date, using the net proceeds of certain equity offerings, subject to certain conditions. Additionally, at any time prior to April 1, 2020, the Company may redeem some or all of the 2022 Notes subject to a make-whole premium plus accrued and unpaid interest to, but excluding, the redemption date. On or after April 1, 2020, the Company may redeem some or all of the 2022 Notes at the applicable redemption prices (expressed as percentages of principal amount) set forth in the table below:

| Redemption on or after | Redemption Price |
|---|---|
| April 1, 2020 | 107.5% |
| April 1, 2021 | 105.0% |
| October 1, 2021 and thereafter | 100.0% |

The Company is not prohibited from acquiring the 2022 Notes by means other than a redemption, whether pursuant to a tender offer, open market purchase or otherwise, so long as the acquisition does not violate the terms of the indenture. Upon the occurrence of a qualifying change of control, the Company is required to offer to repurchase all or any part of the 2022 Notes at a purchase price in cash equal to 101% of the aggregate principal amount of the 2022 Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the date of purchase, subject to the rights of the note holders on the relevant record date to receive interest due on an interest payment date that is on or prior to the date the Company repurchased the notes from the holder.

The 2022 Notes are the Company's senior unsecured obligations and rank equally in right of payment with all of its existing and future senior unsecured debt, and will rank senior in right of payment to all of its future subordinated debt. The 2022 Notes will be effectively subordinated to all of the Company's existing and future secured debt to the extent of the value of the collateral securing such indebtedness.

In connection with the issuance and sale of the 2022 Notes, the Company entered into a registration rights agreement with the initial purchasers. Pursuant to the registration rights agreement, the Company has agreed to file a registration statement with the Securities and Exchange Commission subsequent to an initial public offering of the Company so that the holders may exchange the 2022 Notes for registered notes that have substantially identical terms. In addition, the Company has agreed to exchange the guarantee related to the 2022 Notes for a registered guarantee having substantially the same terms. The Company will use commercially reasonable efforts to cause the exchange to be completed within 365 days following the closing date of an underwritten public offering by ARUH or any parent entity. If the Company fails to comply with certain obligations to register the 2022 Notes, then for the first 90-day period immediately following such failure the interest rate on the 2022 Notes will increase by 0.25% per annum. The interest rate on the 2022 Notes will increase by an additional 0.25% per annum with respect to each subsequent 90-day period the Company fails to comply with its obligations under the registration rights agreement, up to a maximum aggregate increase of 1.0% per annum. Upon regaining compliance with the terms of the registration rights agreement, the increase in interest rate on the 2022 Notes will cease, and the interest rate will return to the initial annual rate of 10.0%.

*Second Lien Term Loans*

In September 2013, the Company entered into the Second Lien Term Loans due September 30, 2018. In November 2016, the Company received equity contributions from the Parent of approximately $654.5 million. These equity contributions, combined with previously received equity contributions, surpassed a defined Additional Equity Contribution threshold within the Second Lien Term Loans credit agreement, which resulted in the interest rate decreasing to 9.5% plus the greater of 1.5% or the 3-month London Interbank Offered Rate (LIBOR). Additionally, the Company no longer had the ability to elect to pay up to 2.0% of interest in kind. Previously, the Second Lien Term Loans bore interest at a rate of 11.5% plus the greater of 1.5% or the 3-month LIBOR with the option to elect to pay up to 2.0%, on a per annum basis, of interest in kind, which was compounded and added to the unpaid principal amount of the loan.

In April 2017, the outstanding $1.290 billion in principal of the Second Lien Term Loans was repaid using proceeds from the issuance of the Company's 2022 Notes as discussed herein. The Company paid approximately $1.372 billion in cash, consisting of $1.290 billion applied to the outstanding principal balance, $71.0 million in early redemption fees and $11.0 million in accrued and unpaid interest, resulting in a loss of $108.4 million, including the write-off of unamortized debt issuance costs and discounts, for the year ended December 31, 2017.

*Convertible Notes*

In February 2014, the Company issued $750.0 million of convertible notes due 2021 (Convertible Notes) at a discount to par value of 5.433%. The proceeds were used for the acquisition of natural gas and oil properties and for general corporate purposes. In August 2014, the Company issued an additional $250.0 million of the Convertible Notes at par for the acquisition of natural gas and oil properties. The Company identified certain embedded features in the Convertible Notes that were required to be bifurcated and accounted for as a derivative. The derivative financial instrument was recorded at fair value as of the date of issuance of the Convertible Notes and is re-measured to fair value as of each subsequent balance sheet date and classified as long-term debt in the consolidated balance sheets. See Note 6 for further discussion of the fair value of the embedded derivative.

The Convertible Notes are due on March 1, 2021. Interest may be paid in cash or in kind semi-annually in arrears on March 1 and September 1 of each year and originally was payable at an annual rate of 3.5%. On March 1, 2016, the interest rate began escalating by 0.5% on each subsequent interest payment date, subject to a maximum interest rate of 6.5% per annum, if a preliminary prospectus relating to a qualified initial public offering (Qualified PO) had not been filed under the Securities Act by such date. The Company has elected to pay interest in kind on each interest payment date since September 2015 and the interest rate, as of December 31, 2017, was 5.5%. Upon maturity, unless earlier paid or converted, the Company will be required to redeem the Convertible Notes at 153.8% of the outstanding principal value, which represents repayment of outstanding principal plus a premium. The Company amortizes the discount on the Convertible Notes to interest expense through the maturity date using the effective interest method.

Conversion of the Convertible Notes into common shares of the qualified public offering issuer (Qualified PO Issuer) following a Qualified PO is at the option of the noteholders. The Qualified PO Issuer may be a business entity that possesses a significant interest in the Company. A Qualified PO is the first public offering of common stock in which the aggregate gross proceeds to the Qualified PO Issuer and the shareholders selling such common stock, if any, equal or exceed $200.0 million and, following such offering, such common stock is listed on a United States securities exchange. Upon conversion, the noteholders will receive common shares of the Qualified PO Issuer equal to the greater of:

1. The aggregate principal amount and accrued interest of the Convertible Notes outstanding on the closing date of the Qualified PO divided by the applicable conversion price. The applicable conversion price is defined as the price per share of common stock in the Qualified PO multiplied by the applicable percentage of the public offering price, which ranges from 80% down to 65% dependent upon the passage of time from the issuance date of the Convertible Notes to the pricing date of the Qualified PO, or

2. The difference between a. and b., as follows:
    a. The common shares of the Qualified PO Issuer immediately prior to considering the effects of conversion divided by one minus a fraction, the numerator is the aggregate principal amount and accrued interest of the Convertible Notes outstanding on the closing date of the Qualified PO and the denominator is the valuation threshold. The valuation threshold refers to an initial equity value of the Company, which is defined as $5.0 billion, subject to adjustments for the Qualified PO. The valuation threshold adjustment will be calculated based upon the equity value of both the Company and the Qualified PO Issuer as of the pricing date of the Qualified PO. The valuation threshold will be adjusted by multiplying the valuation threshold by a fraction. The numerator of said fraction is the equity value of such Qualified PO Issuer, and the denominator is the equity value of the Company.
    b. The common shares of the Qualified PO Issuer immediately prior to considering the effects of conversion.

The Convertible Notes also provide for cash redemption upon a change in control event at the option of the holders at a premium, which as of December 31, 2017 ranged from 142.9% to 153.8% of the principal amount of the Convertible Notes, depending on the change of control date relative to the date issued. The Convertible Notes are not redeemable prior to a change of control or the closing of a Qualified PO. If the closing of a Qualified PO occurs, the Company has the option to redeem all of the Convertible Notes that were not converted at a price equal to 100.0% of the principal of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any.

In January 2016, the Company announced an offer to exchange (Exchange Offer) the outstanding Convertible Notes for newly issued Convertible Notes due 2021 (New Convertible Notes) and an incremental amount of the Company's previously outstanding junior lien debt, which was retired in November 2016. In exchange for each $1,000 principal amount of the Convertible Notes that was validly tendered and not validly withdrawn, the eligible holder received total exchange consideration consisting of (i) $50 principal amount of the junior lien plus an additional principal amount of junior lien corresponding to 5% of any accrued and unpaid interest on the Convertible Notes and (ii) $950 principal amount of the New Convertible Notes plus an additional principal amount of New Convertible Notes corresponding to 95% of any accrued and unpaid interest on the Convertible Notes. The Exchange Offer closed in February 2016, with $661.9 million in aggregate principal amount of the Convertible Notes, representing 90% of the then outstanding principal amount of the Convertible Notes, validly tendered and not validly withdrawn. As a result of the Exchange Offer, the Company issued $639.3 million in aggregate principal amount of the New Convertible Notes, with a discount of $377.2 million, and recognized a gain on exchange of debt of $306.8 million, including the write-off of unamortized debt issuance costs and discounts associated with the Convertible Notes, for the year ended December 31, 2016.

In March 2016, the Company completed a qualified equity sale (Qualified Equity Sale) as defined in the Second Lien Term Loans and on April 1, 2016 provided notice to the holders of the New Convertible Notes that the Company would exercise its option to redeem the New Convertible Notes under the Qualified Equity Sale condition. The redemption price for every $950 principal amount of the New Convertible Notes under the Qualified Equity Sale consisted of $200 principal amount of incremental junior lien together with an additional principal amount for accrued interest and a certain number of the Parent's equity units. In connection with the redemption, the Company issued $138.3 million of incremental junior lien debt, with a discount of $110.7 million, and approximately $237.1 million of equity was issued by the Parent. The redemption resulted in a loss of $4.7 million during the year ended December 31, 2016, including the write-off of unamortized debt issuance costs and discounts.

In March 2017, the Company retired $11.1 million of outstanding principal and accrued and unpaid interest associated with the Convertible Notes contributed to the Company by the Member. Additionally, the Company wrote off $0.8 million of associated discounts and embedded derivative liability, which resulted in an increase to equity of $11.9 million.

*Credit Facilities*

*2017 Credit Facility*. In April 2017, the Company entered into a $1.5 billion senior secured revolving credit facility (2017 Credit Facility) with a fully committed initial borrowing base of $650.0 million and a sublimit for letters of credit of $450.0 million that matures on December 31, 2021. In October 2017, the borrowing base was increased to a fully committed $925.0 million and the sublimit for letters of credit was increased to $647.5 million. The 2017 Credit Facility is secured by liens on substantially all of the Company's assets, including its natural gas and oil properties. The amount available to be borrowed under the 2017 Credit Facility is subject to a borrowing base that is redetermined semiannually as of each April 1 and October 1 based on the Company's proved natural gas, oil and NGL reserves and estimated cash flows from these reserves and its commodity hedge positions. As of December 31, 2017, the Company had no borrowings under the 2017 Credit Facility with $427.7 million of letters of credit outstanding. As of March 7, 2018, the Company had no borrowings under the 2017 Credit Facility with $427.7 million of letters of credit outstanding.

Principal amounts borrowed are payable on the maturity date and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the prime rate announced by the administrative agent, (ii) the Federal Reserve Bank of New York federal funds rate plus 0.5% and (iii) the rate for 1-month Eurodollar loans, plus an applicable margin ranging from 1.75% to 2.75% per annum. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 2.75% to 3.75% per annum. The Company may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

Under the 2017 Credit Facility agreement, the Company is subject to commitment fees payable to the administrative agent at a rate of 0.5% of the unutilized available borrowing base. Additionally, the Company is subject to letter of credit participation fees payable to the administrative agent which escalate based on pre-determined tiers in accordance with the balance of outstanding letters of credit issued. In connection with the participation fee, the Company is also subject to a fronting fee that is payable to the issuing bank at a rate of 0.125% of the balance of outstanding letters of credit issued. During the year ended December 31, 2017, the Company incurred $14.4 million in commitment, participation and fronting fees associated with the 2017 Credit Facility, which are presented as interest expense in the consolidated statements of operations.

The 2017 Credit Facility contains restrictive covenants including, but not limited to, restrictions on the Company's ability to incur additional indebtedness, create certain liens on assets, make certain investments or restricted payments, make loans to others, make certain payments, consolidate or merge, hedge hydrocarbons, enter into transactions with affiliates, dispose of assets, or engage in certain other transactions without the prior consent of the lenders. The 2017 Credit Facility also requires the Company to maintain the following two financial ratios: 1) a consolidated leverage ratio, which requires the Company to maintain a consolidated funded indebtedness to consolidated EBITDAX (as defined in the agreement) ratio of not more than 4.25 to 1.00 for the fiscal quarter ending June 30, 2017 and not more than 4.00 to 1.00 for each fiscal quarter thereafter. For purposes of the consolidated leverage ratio, consolidated EBITDAX is calculated over the trailing four fiscal quarters ending on the date of calculation, provided that for the fiscal quarter ending December 31, 2017, consolidated EBITDAX is calculated as the annualized consolidated EBITDAX based on the period from April 1, 2017 through the end of such fiscal quarter, and 2) a modified current ratio per the covenants, which requires the Company to maintain consolidated current assets to consolidated current liabilities of not less than 1.00 to 1.00 as of the end of each fiscal quarter. As of December 31, 2017, the Company was in compliance with the financial covenants of the 2017 Credit Facility.

As of December 31, 2017, the Company had incurred $13.0 million in unamortized debt issuance costs associated with the 2017 Credit Facility which are presented as other long-term assets in the consolidated balance sheets.

*2016 Credit Facility.* In September 2016, the Company entered into a credit facility (2016 Credit Facility) that was collateralized by first lien mortgages on all of the Company's natural gas and oil properties. The 2016 Credit Facility had a borrowing base of $100.0 million and was scheduled to mature on June 30, 2018. In April 2017, the 2016 Credit Facility was replaced by the 2017 Credit Facility. This resulted in the write-off of $5.6 million in unamortized debt issuance costs.

The principal amount of debt maturities for the five years ended after December 31, 2017 and thereafter are as follows:

| | Principal Amount of Debt Securities |
|---|---|
| | ($ in thousands) |
| 2018 | $ — |
| 2019 | — |
| 2020 | — |
| 2021[(a)] | 130,921 |
| 2022 | 1,500,000 |
| Thereafter | — |
| Total | $ 1,630,921 |

(a) The Convertible Notes due in 2021 include a premium of $45.8 million and interest paid in kind of $35.4 million that are both payable upon maturity. The premium is accreted over the scheduled maturity period of the debt.

*Interest Expense*

Interest expense was comprised of the following:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| Interest expense[(a)] | $ 169,705 | $ 272,357 | $ 225,047 |
| Capitalized interest | (122,273) | (223,650) | (35,524) |
| Long-term debt accretion expense | 12,549 | 24,505 | 84,329 |
| Deferred debt issuance cost amortization | 9,081 | 14,947 | 13,001 |
| Total Interest Expense, net | $ 69,062 | $ 88,159 | $ 286,853 |

(a) Includes interest paid in kind of $3.5 million for the year ended December 31, 2017 compared to $107.7 million and $97.2 million for the years ended December 31, 2016 and 2015, respectively.

**5. Commodity Derivative Instruments**

The Company uses commodity derivative instruments to secure attractive pricing and margins on its share of expected production, to reduce its exposure to fluctuations in future commodity prices and to protect its anticipated operating cash flow against significant market movements or volatility. The Company does not use commodity derivative instruments for speculative or trading purposes. Under the terms of a swap, the Company receives a fixed price for its natural gas or oil production and pays a variable market price to the counterparty. Options are used to establish a floor price (put), a ceiling price (call), or a floor and a ceiling price (collar) for anticipated production. A sold call establishes the maximum price that the Company will receive for contracted commodity volumes. A purchased put establishes the minimum price that the Company will receive for the contracted volumes. Given that the Company's natural gas production is sold at various delivery points that at times may have material spreads or volatility relative to NYMEX, basis swaps may be periodically used to fix or float the differential between product prices at one market location versus another.

All commodity derivative instruments are recognized at their current fair value as either assets or liabilities in the consolidated balance sheets. Changes in the fair value of these commodity derivative instruments are recorded in earnings unless specific hedge accounting criteria are met. The Company elected not to designate any of its commodity derivative instruments for hedge accounting treatment. By using commodity derivative instruments, the Company is exposed to credit risk associated with its hedge counterparties. To minimize such risk, the Company's derivative contracts are with multiple counterparties, reducing its exposure to any individual counterparty. Also, the Company only enters into derivative contracts with counterparties that are creditworthy. The creditworthiness of its counterparties is subject to periodic review.

The following table sets forth the average volumes per day associated with the Company's outstanding natural gas derivative instruments as of December 31, 2017 and the contracted weighted average natural gas prices:

| | | Weighted Average Prices | | |
|---|---|---|---|---|
| | Average Volume (mmbtu/d) | Swap fixed price | Sold call strike price | Purchased put strike price |
| | | | ($/mmbtu) | |
| **Natural gas:** | | | | |
| **Swaps:** | | | | |
| 2018 | 937,000 | $ 3.02 | | |
| 2019 | 1,336,000 | $ 2.88 | | |
| 2020 | 138,000 | $ 2.82 | | |
| **Basis Swaps:** | | | | |
| 2018 | 197,000 | $ (0.20) | | |
| 2019 | 170,000 | $ (0.20) | | |
| **Collars:** | | | | |
| 2018 | 134,000 | | $ 3.27 | $ 3.00 |
| **Call options:** | | | | |
| 2018 | 50,000 | | $ 3.25 | |

The following table sets forth the average volumes per day associated with the Company's outstanding oil derivative instruments as of December 31, 2017 and the contracted weighted average oil prices:

| | Average Volume (bbl/d) | Weighted Average NYMEX ($/bbl) |
|---|---|---|
| **Oil:** | | |
| **Swaps:** | | |
| 2018 | 3,900 | $ 53.47 |
| 2019 | 4,000 | $ 52.64 |

The following tables summarize the classification and fair value amounts of all commodity derivative instruments in the consolidated balance sheets as of December 31, 2017 and 2016, as well as the gross recognized derivative assets and liabilities and amounts offset in the consolidated balance sheets:

| | | December 31, 2017 | | |
|---|---|---|---|---|
| | Consolidated Balance Sheet Classification | Gross Recognized Fair Value | Amounts Netted in Balance Sheet | Net Recognized Fair Value in Balance Sheet |
| | | | ($ in thousands) | |
| Derivative assets: | | | | |
| Natural gas and oil commodity derivatives | Short-term derivative assets | $ 85,522 | $ (9,083) | $ 76,439 |
| Natural gas and oil commodity derivatives | Long-term derivative assets | $ 53,275 | $ (21,834) | $ 31,441 |
| Derivative liabilities: | | | | |
| Natural gas and oil commodity derivatives | Short-term derivative liabilities | $ (17,743) | $ 9,083 | $ (8,660) |
| Natural gas and oil commodity derivatives | Long-term derivative liabilities | $ (26,703) | $ 21,834 | $ (4,869) |

| | Consolidated Balance Sheet Classification | December 31, 2016 Gross Recognized Fair Value | Amounts Netted in Balance Sheet | Net Recognized Fair Value in Balance Sheet |
|---|---|---|---|---|
| | | | ($ in thousands) | |
| Derivative assets: | | | | |
| Natural gas and oil commodity derivatives | Short-term derivative assets | $ 342 | $ (342) | $ — |
| Natural gas and oil commodity derivatives | Long-term derivative assets | $ 652 | $ (652) | $ — |
| Derivative liabilities: | | | | |
| Natural gas and oil commodity derivatives | Short-term derivative liabilities | $ (74,831) | $ 342 | $ (74,489) |
| Natural gas and oil commodity derivatives | Long-term derivative liabilities | $ (20,066) | $ 652 | $ (19,414) |

The following table summarizes the effects of commodity derivative instruments in the consolidated statements of operations for the years ended December 31, 2017, 2016 and 2015:

| | Consolidated Statements of Operations Earnings Caption | Years Ended December 31, 2017 | 2016 | 2015 |
|---|---|---|---|---|
| | | | ($ in thousands) | |
| Natural gas and oil commodity derivatives | Commodity derivative gain (loss) | $ 212,046 | $ (86,434) | $ (2,005) |

## 6. Fair Value Measurements

The Company uses a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets.

Level 2 – Quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; and model-derived valuations whose inputs or significant value drivers are observable.

Level 3 – Unobservable inputs that reflect the Company's own assumptions.

*Fair Value of Derivative Instruments*

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of December 31, 2017 and 2016. The fair values of the natural gas and oil commodity derivatives are based primarily on inputs that are derived from observable data at commonly quoted intervals and are therefore classified as Level 2. See Note 5 for further information on commodity derivative instruments.

| Description | Fair value measurements at December 31, 2017 using: Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| | | ($ in thousands) | | |
| Derivative assets: | | | | |
| Natural gas and oil commodity derivatives | $ — | $ 107,880 | $ — | $ 107,880 |
| Total | $ — | $ 107,880 | $ — | $ 107,880 |
| Derivative liabilities: | | | | |
| Natural gas and oil commodity derivatives | $ — | $ 13,529 | $ — | $ 13,529 |
| Embedded derivative [a] | — | — | 23,891 | 23,891 |
| Total | $ — | $ 13,529 | $ 23,891 | $ 37,420 |

(a) This is included in long-term debt on the consolidated balance sheet as of December 31, 2017.

| Description | Fair value measurements at December 31, 2016 using: Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| | ($ in thousands) | | | |
| Derivative liabilities: | | | | |
| Natural gas and oil commodity derivatives | $ — | $ 93,903 | $ — | $ 93,903 |
| Embedded derivative [(a)] | — | — | 5,403 | 5,403 |
| Total | $ — | $ 93,903 | $ 5,403 | $ 99,306 |

[(a)] This is included in long-term debt on the consolidated balance sheet as of December 31, 2016.

The Company determined that certain embedded features in the Convertible Notes were required to be bifurcated and accounted for as a derivative. The Company determined the fair value of the embedded derivative using a "with" and "without" analysis. This requires (a) estimating the fair value of the Convertible Notes with all the features (including the change of control or Qualified PO premium and the conversion option) within an option pricing framework and (b) subtracting the fair value of the host excluding the embedded derivative. The Company has classified the fair value of the embedded derivative related to the Convertible Notes as Level 3 due to the fact that the valuation is based upon significant unobservable inputs.

The key inputs used to calculate the fair value of the embedded derivative are as follows:

| | December 31, 2017 | 2016 | 2015 |
|---|---|---|---|
| Trading price of Convertible Notes' principal value | 98.0% | 15.0% | 5.0% |
| Probability of Qualified PO or change in control | 5% - 50% with a total of 100% over the expected term | 5% - 50% with a total of 100% over the expected term | 5% - 45% with a total of 100% over the expected term |
| Expected term | Between 0 and 3 years | Between 1 and 3 years | Between 1 and 4 years |
| Discount rate with and without embedded features pre-exit | 11.5% | 46.0% | 70.0% |
| Discount rate without embedded features post-exit | 8.0% | 41.0% | 30.0% |

The following table presents a summary of changes in the fair value of the embedded derivative liability classified as a Level 3 measurement:

| | Years Ended December 31 2017 | 2016 |
|---|---|---|
| | ($ in thousands) | |
| Balance, beginning of period | $ (5,403) | $ (16,025) |
| Change due to purchases or exchanges of debt | 773 | 7,006 |
| Change in fair value [(a)] | (19,261) | 3,616 |
| Balance, end of period | $ (23,891) | $ (5,403) |

[(a)] Included in change in fair value of embedded derivative on the consolidated statements of operations.

*Fair Value of Debt*

The carrying amount and estimated fair value of long-term debt as of December 31, 2017 and 2016 is shown in the table below. The fair value was estimated using Level 2 market data inputs. See Note 4 for further information regarding long-term debt.

| | December 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| | ($ in thousands) | | | |
| 2022 Notes | $ 1,467,465 | $ 1,608,750 | $ — | $ — |
| Second Lien Term Loans | — | — | 1,247,082 | 1,293,490 |
| Convertible Notes | 97,309 | 67,175 | 78,243 | 11,448 |
| Total | $ 1,564,774 | $ 1,675,925 | $ 1,325,325 | $ 1,304,938 |

*Fair Value Measurement on a Nonrecurring Basis*

The initial measurement of asset retirement obligations is recorded at fair value and calculated using discounted cash flow techniques based on internal estimates, including reserve lives and plugging costs, of future retirement costs associated with the natural gas and oil properties. The Company has classified the fair value of the additions to asset retirement obligations as Level 3 due to the fact that the valuation is based upon significant unobservable inputs.

## 7. Related Party Transactions

*Management Services Agreement*

The Company and the Member entered into a management services agreement (Ascent MSA) effective August 1, 2015. Under the Ascent MSA, the Member performs any and all general management, administrative and operating services requested by and at the direction of the Company. The Member invoices the Company monthly for cash it paid for any costs expended on behalf of the Company in performance of the services. The initial term of the agreement was twelve months, and on August 1, 2016 it was automatically extended for an additional twelve months. On August 1, 2017, the agreement was automatically extended on a month-to-month basis and can be terminated by either party upon not less than 30 days notice. The Ascent MSA will be automatically terminated at the earlier of the Company ceasing to hold assets or an initial public offering of the Parent. During the years ended December 31, 2017, 2016 and 2015, the Company incurred approximately $57.9 million, $43.0 million and $26.7 million, respectively, for the services performed under the Ascent MSA, of which $21.5 million, $14.8 million and $3.1 million, respectively, related to direct labor or overhead and was recognized in lease operating expenses or natural gas and oil properties, as applicable. See Note 10 for discussion of the formation of Ascent Resources Management Services, LLC (ARMS), which was assigned all rights, duties, obligations, interests and benefits under the Ascent MSA effective January 1, 2018.

In 2013, the Company entered into a management services agreement (AEU MSA) with AEU Services, LLC (AEU Services), an affiliated entity. Pursuant to the AEU MSA, AEU Services managed the Company's development and operations and provided substantially all of the Company's required operational and support services. Effective August 1, 2015, the AEU MSA was terminated. For the year ended December 31, 2015, the Company incurred costs of $40.8 million for services performed under the AEU MSA, of which $3.5 million related to direct labor or overhead and was recognized in lease operating expenses or natural gas and oil properties, as applicable.

*UMD Agreements*

The Company and UMD are each indirectly, majority owned by investment funds controlled by EMG and First Reserve. In May 2017, the Company and UMD entered into a development agreement (Development Agreement) whereby an AMI was established encompassing Jefferson County, Ohio. Within the AMI, each party will have the option to participate in the acquisition of natural gas and oil interests made by the other party according to an agreed upon pro-rata share of up to 50% for UMD and up to 50% for the Company. Properties acquired by UMD, and not subject to a pre-existing unit operating agreement, will be operated by the Company. Unless terminated at an earlier date by the mutual agreement of the parties, the AMI will remain in effect for the shorter of three years or the date that UMD has, in the aggregate, elected to participate with its pro-rata share of 5,000 net acres within the AMI. For the year ended December 31, 2017, UMD paid the Company $2.9 million for 566 acres pursuant to the Development Agreement.

In August 2017, the Company and UMD completed an acquisition of the Acquisition Properties and entered into the Earn-In Agreement that is discussed in Note 2.

*Transactions Related to Ascent Resources - Marcellus, LLC*

The Company may have excess capacity available on certain firm transportation delivery routes. To minimize excess capacity charges, the Company regularly enters into asset management agreements (AMA) with third parties. Under the AMAs, the Company may direct the third party to purchase natural gas production from Ascent Resources - Marcellus, LLC (ARM), an affiliated entity, to utilize the Company's excess capacity, in the same manner the AMA third party would negotiate and purchase gas from a third party producer. The Company receives a percentage of the margin on the AMA third parties' ultimate sales price to its customers over the price the third parties paid to ARM to purchase the natural gas production. This margin is classified as a reduction to gathering, processing and transportation expenses. For the years ended December 31, 2017 and 2016, the Company recognized $4.2 million and $37.0 million, respectively, related to ARM's production as a reduction to gathering, processing and transportation expenses.

*Related Party Gas Gathering, Firm Transportation and Processing Agreements*

In August 2015, the Company entered into a gas gathering agreement with Jefferson Gas Gathering Company, LLC (Jefferson). EMG has significant influence over Jefferson through its equity investment in Jefferson's parent, MarkWest EMG Jefferson Dry Gas Gathering Company, LLC. The costs incurred under the gas gathering agreement with Jefferson for the years ended December 31, 2017, 2016 and 2015 were approximately $41.2 million, $6.1 million and an immaterial amount, respectively. At December 31, 2017 and 2016, the Company had a payable to Jefferson of $12.8 million and $1.8 million, respectively.

In September 2014, the Company entered into a gas gathering agreement with Ohio Gathering Company, LLC (Ohio Gathering). Ohio Gathering is a joint venture of MarkWest Utica EMG, LLC (MWU EMG). EMG has significant influence over Ohio Gathering through its equity investment in MWU EMG. The Company also entered into a gas processing and fractionation agreement with MWU EMG. The costs incurred for the years ended December 31, 2017, 2016 and 2015 under the gas gathering agreement with Ohio Gathering were $37.5 million, $22.6 million and $11.8 million, respectively. The costs incurred under the gas processing and fractionation agreement with MWU EMG for the years ended December 31, 2017, 2016 and 2015 were $36.5 million, $24.8 million and $14.1 million, respectively. At December 31, 2017 and 2016, the Company had a payable to Ohio Gathering of $6.4 million and $8.0 million, respectively.

In August 2014, the Company entered into a gathering and compression agreement with Ohio River System LLC (ORS). Traverse Midstream Partners LLC (Traverse), an EMG controlled entity, through its subsidiaries owns a 25% interest in ORS. ORS operates a 52-mile natural gas gathering system which was placed in service in the fourth quarter of 2015. The primary term of the agreement is 15 years with an option for the Company to extend the term for one renewal term of five years. The costs incurred during the years ended December 31, 2017, 2016 and 2015 under the gathering and compression agreement with ORS were approximately $22.9 million, $6.5 million and a nominal amount, respectively. At December 31, 2017 and 2016, the Company had a payable to ORS of $3.2 million and $1.5 million, respectively. For information regarding the credit support requirements due to ORS, see Note 8.

In June 2014, the Company entered into a firm transportation agreement with Rover Pipeline LLC (Rover). Traverse, through its subsidiaries, owns a 35% interest in Rover. In October 2017, partial transportation services per the Company's agreement with Rover began and full transportation services provided under the agreement are expected to commence by March 31, 2018. The firm transportation agreement has a primary term of 15 years with an option for the Company to extend the term up to four consecutive times for a term of five years per extension. The costs incurred under the firm transportation agreements with Rover during the year ended December 31, 2017 were $31.5 million. At December 31, 2017, the Company had a payable to Rover of $9.3 million. For information regarding the credit support requirements due to Rover, see Note 8.

In April 2014, the Company entered into a firm transportation agreement with Rockies Express Pipeline LLC (REX). REX is majority owned by Tallgrass Energy Partners, LP (Tallgrass). EMG has significant influence over REX through its indirect equity investments in Tallgrass. Transportation commitments commenced on August 1, 2015, and continue through 2035. Furthermore, in October 2014, the Company entered into an additional firm transportation agreement with REX. Transportation commitments commenced in December 2016 and will continue through 2031. The costs incurred under the firm transportation agreements with REX for the years ended December 31, 2017, 2016 and 2015 were $111.9 million, $82.7 million and $34.2 million, respectively. At December 31, 2017 and 2016, the Company had a payable to REX of $9.4 million and $7.6 million, respectively. For information regarding the credit support requirements due to REX, see Note 8.

*Convertible Notes*

In March 2017, the Company retired $11.1 million of outstanding principal and accrued and unpaid interest associated with Convertible Notes contributed to the Company by the Member. Additionally, the Company wrote off $0.8 million of associated discounts and embedded derivative liability, which resulted in an increase to equity of $11.9 million.

## 8. Commitments and Contingencies

*Litigation Matters*

*Chesapeake Litigation*. In February 2015, Chesapeake Energy Corporation (CHK) filed suit in the District Court of Oklahoma County, Oklahoma against the Company, American Energy Partners, LP (AELP), certain other affiliates of AELP and certain unnamed investors of the Company. In April 2015, the Company, EMG and CHK entered into a settlement agreement (the Settlement Agreement) in connection with this litigation. In exchange for the assignment of a certain amount of leasehold acreage and a combination of contingent cash payments not to exceed $25.0 million, the Company and certain unnamed investors of the Company were dismissed from the lawsuit.

Related to the Settlement Agreement, during the year ended December 31, 2015, the Company recognized $93.0 million in litigation settlement expense, including an estimated $82.0 million for the assignment of certain leasehold acreage to CHK and an $11.0 million accrual for contingent cash payments. During the year ended December 31, 2016, the Company recognized a $4.1 million decrease to the estimated settlement accrual. As of December 31, 2017, all litigation with CHK has been settled.

The Company is periodically involved in litigation and regulatory proceedings, investigations and disputes, including matters relating to commercial transactions, operations, landowner disputes, royalty claims and environmental, health and safety matters. A liability is recognized for any contingency that is probable of occurrence and reasonably estimable. The Company continually assesses the likelihood of adverse judgments or outcomes in these matters, as well as potential ranges of possible losses, based on a careful analysis of each matter and, if necessary, with the assistance of legal counsel and other experts. The Company will continue to monitor the impact that litigation could have on the Company and will assess the impact of future events. Legal defense costs are accounted for in the period the costs are incurred.

Based on management's current assessment, the Company is of the opinion that no pending or threatened lawsuit or dispute relating to the Company's business operations is likely to have a material adverse effect on its future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

*Environmental Matters*

The Company is subject to existing federal, state and local laws and regulations governing environmental matters, such as the Comprehensive Environmental Response, Compensation and Liability Act and similar statutes. From time to time, the Company is party to various environmental and regulatory proceedings in the ordinary course of business. Management does not believe the results of these environmental proceedings, individually or in the aggregate, will have a material adverse effect on the Company.

*Commitments*

The following table presents the Company's undiscounted commitments under unconditional purchase obligations, excluding any reimbursement from working interest and royalty interest owners, where appropriate, or credits for third party volumes, that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2017:

| Period | Pipeline Transportation | Drilling Rigs | Operating Leases | Total |
|---|---|---|---|---|
| | | ($ in thousands) | | |
| 2018 | $ 557,339 | $ 9,333 | $ 679 | $ 567,351 |
| 2019 | 605,529 | 7,363 | 654 | 613,546 |
| 2020 | 635,944 | — | 260 | 636,204 |
| 2021 | 648,692 | — | — | 648,692 |
| 2022 | 655,618 | — | — | 655,618 |
| Thereafter | 7,467,420 | — | — | 7,467,420 |
| Total | $ 10,570,542 | $ 16,696 | $ 1,593 | $ 10,588,831 |

*Pipeline Transportation Commitments*

As of December 31, 2017, the Company had certain pipeline transportation commitments which will reduce the impact of possible production curtailments that may arise due to limited transportation capacity. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. To enter into certain of these commitments, the Company made certain deposits, all of which have been reimbursed and replaced by letters of credit. The deposits at December 31, 2016 are shown as deposits on pipeline transportation on the consolidated balance sheets, and there are no deposits outstanding as of December 31, 2017.

As discussed in Note 7, the Company entered into certain firm transportation agreements with ORS and Rover. The Company is obligated to provide ORS with credit support ranging from $40.0 million to $75.0 million. The Company is obligated to provide Rover with credit support in the amount of one year of demand charges, which may reach $250.1 million.

Pursuant to an agreement (the Pledge Agreement) between the Company and Traverse, Traverse was required to satisfy the Company's credit obligation to ORS (the ORS Pledge) and to Rover (the Rover Pledge). Commencing February 1, 2016 for the ORS Pledge and July 1, 2016 for the Rover Pledge and until such time as the Pledge Agreement was terminated, the Company paid Traverse an amount equal to 2.75% per annum, increasing on each August 1 and July 1, respectively, thereafter by 0.25% per annum (capped at 4.0%), payable quarterly in arrears, on the value of the collateral posted by Traverse under the Pledge Agreement. In April 2017, the Pledge Agreement, and corresponding ORS and Rover Pledges, were terminated after the Company purchased and retired the Second Lien Term Loans and provided collateral directly to ORS and Rover in the form of letters of credit under the 2017 Credit Facility. During the years ended December 31, 2017 and 2016 the Company incurred $2.2 million and $3.9 million, respectively, in interest expense associated with the credit support obligations for the ORS and Rover Pledges. As of December 31, 2017, the Company had issued a $40.0 million letter of credit to ORS and $241.3 million in letters of credit to Rover.

As discussed in Note 7, the Company entered into certain firm transportation agreements with REX. The Company is obligated to provide REX with credit support for its transportation commitments. During 2017, the Company was refunded $50.8 million in cash deposits previously made upon the issuance of letters of credit under the 2017 Credit Facility for the same amount to satisfy the obligation. As of December 31, 2017, the Company has issued $67.8 million in the form of letters of credit and has $61.6 million in surety bonds outstanding as collateral to satisfy its transportation commitments with REX.

*Drilling Rig Commitments*

The Company has entered into various drilling rig contracts to utilize drilling services at market-based pricing. The Company's drilling rig commitments were entered into in the ordinary course of business to ensure rig availability allowing the Company to execute its business objectives. These commitments are reflected in the table above.

*Operating Lease Commitments*

The Company leases certain equipment and office space. Lease expense related to operating leases totaled $1.3 million, $0.6 million and $0.8 million in 2017, 2016 and 2015, respectively.

*Joint Venture Commitments*

In 2013, the Company entered into a joint venture participation agreement in order to acquire interests in unproved leasehold. Under the agreement, the Company is required to pay the seller's retained share of development costs (carried costs) for certain wells and other development operations that occur within an AMI as defined in the agreement. The acquisition obligation represents the difference in the purchase price of the interests in unproved leasehold and the cash paid by the Company. The agreement further stipulates that if the Company fails to repay its obligation for such carried costs by certain periods of time, then the Company will be required to pay the seller any shortfall in cash. In February 2016, the Company executed an amendment to extend the payment terms of carried costs from four years to five years. In November 2017, the Company executed a second amendment to expand the AMI and reduce the cash carry obligations by $21.8 million with the closing of the Company's divestiture of certain oil and gas properties in lieu of a cash payment. See Note 2 for more details of this transaction. As of December 31, 2017 and 2016, the Company owed $61.1 million and $103.3 million, respectively, for this obligation. This obligation has been discounted using an 11% discount rate, to reflect the imputation of interest, and is classified as a current liability on the consolidated balance sheet as of December 31, 2017.

In 2014, the Company entered into a joint venture participation agreement. The related carry balance was $79.7 million as of December 31, 2016, which the Company satisfied and closed in November 2017. All of the remaining acreage entitled to the Company under the joint venture agreement was conveyed to the Company.

*Contingency*

The Utica Acquisition includes contingent consideration of up to $15.0 million if the average daily price of oil per the West Texas Intermediate (WTI) is greater than certain pre-defined prices in 2018, 2019 and 2020, respectively. As of December 31, 2017, due to the significant volatility in oil prices in recent years, it was concluded that no accrual was necessary. This contingency will be reassessed quarterly to determine if an accrual should be recorded in the future.

**9. Other Current Liabilities**

The Company's other current liabilities consisted of the following as of December 31, 2017 and 2016:

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| | ($ in thousands) | |
| Drilling and completion accrual | $ 96,944 | $ 60,448 |
| Gathering, processing and transportation expense accrual | 55,541 | 28,915 |
| Other | 47,615 | 25,072 |
| Total Other Current Liabilities | $ 200,100 | $ 114,435 |

**10. Subsequent Events**

The Company evaluated its December 31, 2017 consolidated financial statements for subsequent events through March 7, 2018, the date the consolidated financial statements were available to be issued, and such events are noted below.

*Ascent Resources Management Services, LLC*

In an effort to bring all management services under direct control of the Company, ARMS, a wholly-owned subsidiary of the Company, was formed in August 2017. Effective January 1, 2018, the Member assigned all rights, duties, obligations, interests and benefits under the Ascent MSA to ARMS. As part of the management services agreement, ARMS performs any and all general management, administrative and operating services requested by and at the direction of the Company. The Company does not anticipate a material effect on its consolidated financial statements.

## 11. Supplemental Information on Natural Gas, Oil and NGL Producing Activities (Unaudited)

The following disclosures provide supplemental unaudited information regarding the Company's natural gas, oil and NGL activities, which are entirely within the United States:

*Costs Incurred In Natural Gas and Oil Property Acquisition, Exploration and Development*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| Acquisition costs of properties: | | | |
| Proved properties | $ 32,261 | $ 3,662 | $ 1,837 |
| Unproved properties | 386,789 | 497,144 | 281,955 |
| Total property acquisition costs | 419,050 | 500,806 | 283,792 |
| Exploration costs | 2,269 | 17,136 | 13,277 |
| Development costs | 683,616 | 265,280 | 722,693 |
| Total | $ 1,104,935 | $ 783,222 | $ 1,019,762 |

Costs incurred in the table above include additions to asset retirement obligations of a nominal amount for each of the years ended December 31, 2017, 2016 and 2015, respectively.

*Capitalized Costs Relating to Natural Gas, Oil and NGL Producing Activities*

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| | ($ in thousands) | |
| Proved | $ 3,322,876 | $ 2,094,137 |
| Unproved | 1,118,736 | 1,544,482 |
| Total | 4,441,612 | 3,638,619 |
| Accumulated depreciation, depletion and amortization | (674,186) | (368,663) |
| Net Capitalized Costs | $ 3,767,426 | $ 3,269,956 |

*Natural Gas, Oil and NGL Reserves*

Proved reserves are estimated volumes of natural gas, oil and NGL that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Net quantities of proved reserves exclude royalties and interests owned by others. The proved natural gas, oil and NGL reserves for the years ended December 31, 2017, 2016, and 2015 were prepared by the Company's reservoir engineers utilizing analogy to offset production, volumetrics, conventional decline curve analysis and rate transient analysis. Type curves were developed in a collaborative effort between the Company's engineers and geoscientists and consultants from W.D. Von Gonten & Co (WDVG), and are periodically updated based on the additional well performance data available. Proved reserve estimates for the years ended December 31, 2017, 2016, and 2015 were also independently prepared by Software Integrated Solutions (SIS) (formerly known as PetroTechnical Services), a Division of Schlumberger Technology Corporation. SIS reviewed the Company's type curves for reasonableness and benchmarked them with their own independent analysis from a sampling of the Company's type curves. SIS' results were in reasonable agreement with the Company's results; therefore, they used the Company's type curves as the basis for their reserves projections.

Proved reserve estimates included herein conform to the definitions prescribed by the U.S. Securities and Exchange Commission (SEC). In accordance with SEC Regulation S-X, Rule 4-10, as amended, the Company uses the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month within the 12-month period prior to the end of the reporting period. There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future production rates and timing of future development costs.

As of December 31, 2017, all of the Company's assets were located in the Utica Shale in Ohio. The following table sets forth proved reserves during the periods indicated for the Company:

| | Natural Gas (mmcf) | Oil (mbbls) | NGL (mbbls) | Total (mmcfe)[(a)] |
|---|---|---|---|---|
| Proved Reserves at December 31, 2014 | 740,744 | 16,704 | 18,562 | 952,339 |
| Extensions, discoveries and other additions | 604,072 | 14,043 | 15,869 | 783,544 |
| Revisions | 43,095 | (2,808) | (3,164) | 7,269 |
| Sales of reserves | (153,579) | — | — | (153,579) |
| Production | (38,355) | (1,706) | (1,242) | (56,044) |
| Proved Reserves at December 31, 2015 | 1,195,977 | 26,233 | 30,025 | 1,533,529 |
| Extensions, discoveries and other additions | 629,197 | 3,602 | 2,916 | 668,304 |
| Revisions | (231,492) | (2,410) | (3,621) | (267,675) |
| Production | (109,714) | (2,035) | (2,588) | (137,451) |
| Proved Reserves at December 31, 2016 | 1,483,968 | 25,390 | 26,732 | 1,796,707 |
| Extensions, discoveries and other additions | 2,290,332 | 7,774 | 9,100 | 2,391,578 |
| Revisions | 416,389 | (5,866) | 5,398 | 413,573 |
| Purchases of reserves | 37,173 | 531 | 306 | 42,198 |
| Sales of reserves | (75,036) | (3,172) | (2,743) | (110,526) |
| Production | (240,980) | (2,492) | (3,286) | (275,653) |
| Proved Reserves at December 31, 2017 | 3,911,846 | 22,165 | 35,507 | 4,257,877 |
| | | | | |
| Proved developed reserves: | | | | |
| December 31, 2015 | 363,208 | 9,490 | 11,108 | 486,799 |
| December 31, 2016 | 582,499 | 11,487 | 15,015 | 741,508 |
| December 31, 2017 | 1,445,354 | 8,762 | 14,622 | 1,585,659 |
| | | | | |
| Proved undeveloped reserves: | | | | |
| December 31, 2015 | 832,769 | 16,743 | 18,917 | 1,046,730 |
| December 31, 2016 | 901,468 | 13,903 | 11,719 | 1,055,199 |
| December 31, 2017 | 2,466,492 | 13,403 | 20,885 | 2,672,218 |

(a) Oil and NGL are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and NGL to natural gas, which is not necessarily indicative of the relationship of oil and NGL to natural gas prices.

During the year ended December 31, 2017, the Company added approximately 2.4 tcfe in proved reserves through the continued development of its Utica Shale acreage. Revisions of previous estimates included upward revisions of 585.5 bcfe due to higher commodity prices, upward revisions of 7.9 bcfe due to improved drilling and operating efficiencies offset by downward revisions of 179.8 bcfe due to removing proved undeveloped reserves where it was determined development would occur outside of the Company's five year development plan. As of December 31, 2017, all proved undeveloped locations are in accordance with the SEC five year rule. The Company added proved reserves through acquisitions of 42.2 bcfe and reduced proved reserves through divestitures of 110.5 bcfe. The unadjusted 12-month average prices used to calculate reserves at December 31, 2017 were $2.98 per mmbtu for natural gas and $51.34 per barrel for oil and condensate.

During the year ended December 31, 2016, the Company added 668.3 bcfe in proved reserves through drilling activities and evaluation of proved areas in the Utica Shale. The Company did not add or reduce significant proved reserves through acquisitions or divestitures. The majority of the downward revisions of 267.7 bcfe relates to negative price revisions of 356.6 bcfe, which more than offset the positive performance revisions of 88.9 bcfe for the existing properties. As of December 31, 2016 all proved undeveloped locations are in accordance with the SEC five year rule. The unadjusted 12-month average prices used to calculate reserves at December 31, 2016 were $2.48 per mmbtu for natural gas and $42.75 per barrel for oil and condensate.

During the year ended December 31, 2015, the Company added 783.5 bcfe in proved reserves through drilling activities and evaluation of proved areas in the Utica Shale. The Company did not add significant proved reserves through acquisitions, however, the Company divested 153.6 bcfe. As of December 31, 2015 all proved undeveloped locations are in accordance with the SEC five year rule. The unadjusted 12-month average prices used to calculate reserves at December 31, 2015 were $2.59 per mmbtu for natural gas and $50.28 per barrel for oil and condensate.

All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. These rules require that the standard of “reasonable certainty” be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond the Company’s control such as reservoir performance, prices, economic conditions and government regulation. In addition, drilling, testing and producing subsequent to the date of an estimate may justify revisions of estimates.

Reserve estimates are often different from the quantities of natural gas, oil and NGL that are ultimately recovered. Estimating quantities of proved natural gas, oil and NGL reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based and upon economic factors, such as natural gas, oil and NGL prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effects of governmental regulation. In addition, due to the lack of substantial, if any, production data, there are greater uncertainties in estimating proved undeveloped reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, the Company’s reserve estimates are inherently imprecise.

The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties the Company owns declines as reserves are depleted. Except to the extent the Company conducts successful exploration and development activities or acquires additional properties containing proved reserves, or both, the Company’s proved reserves will decline as reserves are produced. Subsequent to December 31, 2017, there have been no major discoveries, favorable or otherwise, that may be considered to have caused a significant change in the Company’s estimated proved reserves at December 31, 2017.

*Results of Operations for Natural Gas, Oil and NGL Producing Activities*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| Revenues | $ 895,361 | $ 367,149 | $ 177,918 |
| Lease operating expenses | (35,259) | (24,061) | (21,119) |
| Gathering, processing and transportation expenses | (341,765) | (186,300) | (86,973) |
| Production and ad valorem taxes | (14,050) | (7,623) | (2,504) |
| Exploration expenses | (186,152) | (269,982) | (85,394) |
| Acquisition expenses | — | — | (1,403) |
| Natural gas and oil depreciation, depletion and amortization | (305,573) | (229,038) | (133,410) |
| Results of Operations | $ 12,562 | $ (349,855) | $ (152,885) |

*Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| Future cash inflows | $ 12,671,869 | $ 5,157,113 | $ 3,261,880 |
| Future production costs | (6,349,919) | (2,901,683) | (726,984) |
| Future development costs | (1,451,743) | (595,058) | (752,153) |
| Future net cash flows | 4,870,207 | 1,660,372 | 1,782,743 |
| Discount to present value at 10% annual rate | (2,573,628) | (804,018) | (881,423) |
| Standardized Measure of Discounted Future Net Cash Flows | $ 2,296,579 | $ 856,354 | $ 901,320 |

*Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | | ($ in thousands) | |
| Standardized Measure of Discounted Future Net Cash Flows, beginning of period | $ 856,354 | $ 901,320 | $ 1,305,225 |
| Sales of natural gas, oil and NGL produced, net of production costs | (504,287) | (149,166) | (67,322) |
| Net changes in prices and production costs | 185,725 | (318,823) | (945,554) |
| Extensions and discoveries, net of production and development costs | 1,212,246 | 274,008 | 455,498 |
| Changes in future development costs | (350,380) | 165,369 | 28,387 |
| Development costs incurred during period that reduced future development costs | 116,498 | 124,389 | 209,563 |
| Revisions of previous quantity estimates | 648,911 | (171,887) | (69,690) |
| Purchase of reserves | 19,278 | — | — |
| Sales of reserves | (77,916) | — | (84,001) |
| Accretion of discount | 85,635 | 90,132 | 130,522 |
| Changes in production rates and other | 104,515 | (58,988) | (61,308) |
| Standardized Measure of Discounted Future Net Cash Flows, end of period | $ 2,296,579 | $ 856,354 | $ 901,320 |