MANAGEMENT'S DISCUSSION AND ANALYSIS AND
CONSOLIDATED FINANCIAL STATEMENTS

Ascent Resources – Utica, LLC

As of December 31, 2016 and 2015, and for the years ended December 31, 2016, 2015 and 2014.

ASCENT RESOURCES – UTICA, LLC
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Discussion and Analysis of Financial Condition and Results of Operations	1
Report of Independent Auditors	13
Consolidated Balance Sheets as of December 31, 2016 and 2015	14
Consolidated Statements of Operations for the Years Ended December 31, 2016, 2015 and 2014	15
Consolidated Statements of Member's Equity for the Years Ended December 31, 2016, 2015 and 2014	16
Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014	17
Notes to Consolidated Financial Statements	19
Supplemental Information on Natural Gas and Oil Producing Activities (Unaudited)	42

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

Our Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with our consolidated financial statements and accompanying notes, included herein. This 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 are based on our current plans, objectives, goals, strategies, estimates, assumptions and projections about our industry, business, and future financial results. Our actual results may differ materially from those anticipated in these forward-looking statements.

Unless otherwise indicated or the context otherwise requires, references in this MD&A section to "ARU", "we", "our", "us", and "the Company" refer to Ascent Resources – Utica, LLC.

Overview

We are engaged in the acquisition, exploration, development, production and operation of natural gas and oil properties located in the Utica Shale in Ohio. We are focused on building value for investors by leveraging our operations and management expertise to develop a large portfolio of repeatable, low-risk, high-return wells within the Utica Shale.

Our Company was founded in June 2013 and was initially capitalized in September 2013 with contributions to Ascent Resources Utica Holdings, LLC (the Member). The contributions were provided by the Energy & Minerals Group (EMG), First Reserve Corporation (First Reserve), other institutional investors and entities associated with the management of American Energy Partners, LP (AELP) (collectively, the Sponsors).

Effective December 31, 2014, the Member and its subsidiaries were reorganized and were contributed to Ascent Resources Operating, LLC (ARO), a subsidiary of Ascent Resources, LLC (our Parent). EMG controls our Parent as a result of the number of managers it can designate to the board of managers of our Parent. The Parent, a Delaware limited liability company, was formed on October 13, 2014, to effect the combination of the Company and our affiliate, Ascent Resources – Marcellus, LLC. Prior to the reorganization, EMG controlled the Company through the board of managers of the Member and its ownership interest in the Member.

During the year ended December 31, 2016, our Member contributed $1.3 billion of equity capital raised by the Parent. The capital contributed to us consisted of $1.1 billion in cash proceeds from equity contributions and $177.0 million of additional cash proceeds from the senior subordinated loan agreement with the Member (Note Payable to Member). In September 2016, the $505.7 million of outstanding Note Payable to Member along with all accrued and unpaid interest was converted to equity.

As of December 31, 2016, we had 108 gross operated wells producing and an interest in 165 gross non-operated producing wells compared to 77 gross operated wells producing and an interest in 118 gross non-operated producing wells at December 31, 2015 and 31 gross operated wells producing and an interest in 47 gross non-operated producing wells at December 31, 2014.

Energy Industry Environment

In late 2014, natural gas, oil and natural gas liquids (NGL) prices declined precipitously as a result of several factors, including increased supplies, relatively mild weather in the United States, and relatively weak global economic growth, leading to lower demand. These prices remained depressed through the end of 2015 and into 2016. Specifically, Henry Hub natural gas prices declined from approximately $4.80 per mmbtu in April 2014 to below $1.60 per mmbtu in March 2016, and have recently traded at approximately $3.00 per mmbtu. NYMEX prices of domestic oil fell significantly from approximately $106.00 per barrel in June 2014 to below $27.00 per barrel in January 2016, and have recently traded at approximately $50.00 per barrel. Continued low natural gas, oil and NGL prices in the future will not only further decrease our revenues, but will also reduce the amount of natural gas, oil and NGL that we can produce economically and therefore potentially lower our natural gas, oil and NGL reserves. A substantial or extended decline in natural gas, oil and NGL prices may result in impairments of our proved natural gas and oil properties and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and ability to meet our debt service requirements.

Financial Data

The following table sets forth certain information regarding our production volumes, natural gas, oil and NGL sales, average sales prices received, and other operating income and expenses for the periods indicated:

	Years Ended December 31,		
	2016	2015	2014
Net Production Volumes:			
Natural gas (mmcf)	109,714	38,355	9,848
Oil (mbbl)	2,035	1,706	257
NGL (mbbl)	2,588	1,242	234
Natural Gas Equivalent (mmcfe)	137,451	56,044	12,796
Natural Gas, Oil, and NGL Sales ($ in thousands):			
Natural gas	$ 262,765	$ 100,311	$ 32,159
Oil	67,551	62,461	17,705
NGL	36,833	15,146	8,277
Commodity derivative loss	(86,434)	(2,005)	—
Total	$ 280,715	$ 175,913	$ 58,141
Average Daily Production Volumes:			
Natural gas (mmcf/d)	300	105	27
Oil (mbbl/d)	6	5	1
NGL (mbbl/d)	7	3	1
Natural Gas Equivalent (mmcfe/d)	376	154	35
Average Sales Prices, Before Derivatives:			
Natural gas ($ per mcf)	$ 2.39	$ 2.62	$ 3.27
Oil ($ per bbl)	$ 33.19	$ 36.60	$ 68.89
NGL ($ per bbl)	$ 14.23	$ 12.20	$ 35.37
Natural Gas Equivalent ($ per mcfe)	$ 2.67	$ 3.17	$ 4.54
Operating Expenses ($ per mcfe):			
Natural gas, oil and NGL production	$ 0.18	$ 0.38	$ 0.53
Natural gas, oil and NGL gathering, processing and transportation	1.36	1.55	1.54
Production and ad valorem taxes	0.05	0.04	0.03
Exploration expenses	1.96	1.53	1.80
General and administrative expenses	0.05	0.28	4.87
General and administrative expenses – related party	0.23	1.09	4.81
Incentive units expense	—	(0.09)	3.09
Litigation settlement expense (benefit)	(0.03)	1.66	—
Impairment of other property and equipment	0.02	—	—
Natural gas, oil and NGL depreciation, depletion and amortization	1.67	2.38	1.66
Depreciation and amortization of other assets	0.01	0.01	0.02
Loss on divestiture of natural gas, oil and NGL properties	—	3.67	—
Total Operating Expenses	$ 5.50	$ 12.50	$ 18.35

The following table summarizes our other income (expense) for the periods indicated:

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Interest expense, net	$ (142,225)	$ (311,523)	$ (184,870)
Acquisition obligation accretion expense	(10,108)	(17,118)	(18,212)
Change in fair value of embedded derivative	3,616	211,593	16,412
Gains (losses) on purchases or exchanges of debt	207,470	(25,831)	—
Gain on bargain purchase	—	—	36,135
Other income	2,001	2,596	933
Total Other Income (Expense)	$ 60,754	$ (140,283)	$ (149,602)

Liquidity and Capital Resources

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 Member raised by our Parent, asset sales and proceeds from the issuance of debt. Equity contributions from our Member, cash on hand, cash flow from operations, future draws on our credit facility and other operating transactions will be the primary sources of liquidity in the future.

As of December 31, 2016, we had a cash balance of approximately $268.5 million. During 2016, our Member contributed $1.3 billion of equity capital raised by the Parent. The capital contributed to us consisted of $1.1 billion in cash proceeds from equity contributions and $177.0 million of additional cash proceeds from the issuance of additional Note Payable to Member. There were no outstanding borrowings or letters of credit issued under the 2016 Credit Facility as of December 31, 2016. See Note 4 of the notes to our consolidated financial statements included in this report for additional information regarding the Company's credit facilities. As of March 16, 2017, there was one $16.9 million letter of credit outstanding, which reduced our availability under the facility to $83.1 million. Based on our current cash balance, credit facility availability and expected operating cash flows, we expect to be able to satisfy all of our financial obligations and commitments in 2017.

We anticipate a significant increase in our revenues in 2017 due to expected increased production and higher realized prices compared to 2016. 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, our ability to generate positive operating cash flows in a low commodity price environment, raise additional capital, sell assets, or take any other action to improve our liquidity is subject to risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control.

Our strategy for 2017 includes evaluating options in the context of a dynamic commodity price and service costs environment and we plan to opportunistically execute financial and operating transactions to improve our liquidity and optimize our capital structure and balance sheet.

2016 Credit Facility

In September 2016, the Company entered into a credit facility that is collateralized by first lien mortgages on all of ARU's natural gas, oil and NGL properties (2016 Credit Facility). The 2016 Credit Facility has a borrowing base of $100.0 million. The 2016 Credit Facility matures on June 30, 2018 but shall be automatically extended to June 25, 2019 if (a) no later than September 30, 2017 the Company provides evidence that the maturity date of 100% of the outstanding second lien loans (ARU Second Lien Term Loans) and all other qualified indebtedness has been extended beyond September 26, 2019, or all such debt has been fully repaid or converted into or exchanged for equity interests and (b) on the date the Company provides such evidence of extension or repayment, no event of default exists.

Borrowings under the 2016 Credit Facility may be designated as either alternate base rate (ABR) loans or eurodollar loans. ABR loans bear interest at the greater of the prime rate, the federal funds effective rate plus 0.50%, or the adjusted LIBOR plus 1.00%, plus, in each case, the applicable margin, as defined in the agreement, and is paid quarterly. Eurodollar loans bear interest at the adjusted LIBOR plus the applicable margin and is paid on the last day of the interest period, if shorter than three months, or every three months. There were no outstanding borrowings or letters of credit issued under the 2016 Credit Facility as of December 31, 2016. As of March 16, 2017, we had one outstanding $16.9 million letter of credit, which reduced the availability under the facility to $83.1 million.

The 2016 Credit Facility contains 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, consolidate or merge, enter into transactions with affiliates or dispose of assets.

The 2016 Credit Facility also contains certain financial maintenance covenants. The Company must maintain an EBITDAX to interest expense ratio of 1.00 to 1.00 for the quarter ending March 31, 2017; 1.25 to 1.00 for the quarter ending June 30, 2017, and 1.50 to 1.00 for each fiscal quarter ending on or after September 30, 2017. The Company must also maintain a first lien debt to EBITDAX ratio not to exceed 1.50 to 1.00 for the quarters ending March 31, 2017 and June 30, 2017; 2.00 to 1.00 for the quarters ending September 30, 2017 and December 31, 2017; and 2.50 to 1.00 for each fiscal quarter ending on or after March 31, 2018. For purposes of this covenant, total debt only includes indebtedness under the 2016 Credit Facility. At December 31, 2016, the Company was in compliance with the covenants of the 2016 Credit Facility.

As of December 31, 2016, the Company had incurred $7.0 million in unamortized debt issuance costs associated with the 2016 Credit Facility, which are presented as an other long-term asset.

ARU Second Lien Term Loans

We are party to an amended and restated credit agreement (the ARU Second Lien Credit Agreement) among ARUH, as parent, ARU, as borrower, ARU Finance Corporation, as loan party, Wilmington Trust, National Association, as administrative agent and collateral agent, and certain lenders party thereto. The ARU Second Lien Credit Agreement provides for $1.2 billion in ARU Second Lien Term Loans and from inception through November 14, 2016, the Company had the option to pay a portion of interest due on each interest payment date through payments in kind, increasing the principal amount to $1.3 billion as of December 31, 2016. The ARU Second Lien Term Loans mature on September 30, 2018 and bear interest at a rate per annum equal to LIBOR plus 9.50%, subject to a LIBOR "floor" equal to 1.50%. ARU is able to prepay amounts outstanding under the ARU Second Lien Credit Agreement at any time subject to payment of certain prepayment premiums. The prepayment premium is equal to 5.50% of the amount of the ARU Second Lien Term Loans being prepaid if the ARU Second Lien Term Loans are prepaid on or after September 30, 2016 and prior to September 30, 2017 and 2.5% on or after September 30, 2017 to maturity. The ARU Second Lien Credit Agreement is secured by substantially all of our assets, including by mortgages on substantially all of ARU's natural gas, oil and NGL properties, and has the benefit of guarantees from ARU's subsidiaries.

The ARU Second Lien Credit Agreement contains 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, consolidate or merge, enter into transactions with affiliates or dispose of assets. At December 31, 2016 and 2015, ARU was in compliance with the covenants of the ARU Second Lien Credit Agreement. During the first quarter of 2016, the ARU Second Lien Credit Agreement was amended to include the following financial maintenance covenants for 2017: ARU's total debt to EBITDAX be no greater than 7.75 to 1.00 for the quarters ending March 31, 2017, June 30, 2017, and September 30, 2017; 7.50 to 1.00 for the quarter ending December 31, 2017; 7.00 to 1.00 for the quarter ending March 31, 2018; 6.50 to 1.00 for the quarter ending June 30, 2018; and 6.00 to 1.00 for each fiscal quarter ending on or after September 30, 2018. For purposes of this covenant, total debt excludes indebtedness under the ARU Convertible Notes.

ARU Convertible Notes

In February 2014, the Company and ARU Finance Corporation co-issued $750.0 million aggregate principal amount of convertible notes pursuant to an indenture by and between the Company and Wilmington Trust, National Association, as trustee (ARU Convertible Notes). In August 2014, the Company issued an additional $250.0 million of ARU Convertible Notes. As a result of the offer to exchange (Exchange Offer) the outstanding ARU Convertible Notes for newly issued 3.5% ARU Convertible Notes due 2021 (New ARU Convertible Notes) in February 2016, and the redemption of the New ARU Convertible Notes in April 2016, an aggregate principal amount of $76.3 million was outstanding as of December 31, 2016.

Interest on the ARU Convertible Notes was initially payable at an annual rate of 3.50% per annum in cash or in kind semi-annually in arrears on March 1 and September 1 of each year. The interest rate escalates by 0.50% on each interest payment date, beginning March 1, 2016, if a preliminary prospectus relating to a qualified initial public offering (Qualified PO) has not been filed under the Securities Act by such date, subject to a maximum interest rate of 6.50% per annum. We have elected to pay interest in kind on each interest payment date since September 2015 and the current interest rate, as of March 1, 2017, is 5.0%. The ARU 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 ARU 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 ARU Convertible Notes may be converted into common shares of the initial public offering issuer at the option of the noteholders.

The ARU Convertible Notes also provide for cash redemption upon a change in control event at the option of the holders at a premium ranging from 125.0% to 153.8% of the face value of the ARU Convertible Notes, depending on the change of control date relative to the date issued. The ARU 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, ARU has the option to redeem all of the ARU Convertible Notes that were not converted at a price equal to 100.0% of the principal of the ARU Convertible Notes to be redeemed, plus accrued and unpaid interest, if any.

Note Payable to Member

In June 2015, the Company received $250.0 million in cash proceeds from the initial issuance of the Note Payable to Member and $177.0 million in cash proceeds from the issuance of additional Note Payable to Member during the first quarter of 2016. The maturity date of the Note Payable to Member was the 91st day after the latest senior debt maturity date.

The Note Payable to Member bore interest at a rate of 17% which was paid in kind, compounded and added to the unpaid principal amount of the loan on a quarterly basis. During the years ended December 31, 2016 and 2015, the Company incurred $54.1 million and $24.7 million, respectively, of interest in kind.

The Note Payable to Member was to be converted into membership interests of the Company upon the earliest of the following, with defined terms similar to the ARU Convertible Notes: (a) the closing date of a Qualified PO, (b) the date on which all outstanding ARU Convertible Notes are converted into common stock of the Qualified PO Issuer, (c) satisfaction and discharge of the ARU Convertible Notes prior to the conversion of all outstanding ARU Convertible Notes into common stock or (d) entry by the Company into a first lien credit facility.

In September 2016, the Company's entry into the 2016 Credit Facility triggered the conversion of $505.7 million of the outstanding Note Payable to Member including all accrued and unpaid interest into equity.

Historical Cash Flows

Net Cash Provided by or Used in Operating Activities

Net cash flow provided by operating activities was approximately $92.1 million for the year ended December 31, 2016, compared to $160.0 million used in operating activities for the year ended December 31, 2015 and compared to $150.6 million used in operating activities for the year ended December 31, 2014. The increase in operating cash flow from the year ended December 31, 2015 to the year ended December 31, 2016, was the result of an increase in natural gas, oil and NGL sales and a positive change in working capital levels. The decrease in operating cash flow from the year ended December 31, 2014 to the year ended December 31, 2015 was the result of lower revenues due to depressed commodity prices, an increase in cash operating expenses, interest expense and changes in working capital levels that were primarily offset by an increase in natural gas, oil and NGL sales.

Net Cash Used in Investing Activities

Net cash flow used in investing activities was comprised of the following:

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Investing activities:			
Drilling and completion costs	$ (268,082)	$ (760,435)	$ (205,070)
Acquisitions of proved and unproved natural gas, oil and NGL properties	(428,301)	(217,677)	(1,922,067)
Proceeds from divestitures of proved and unproved natural gas, oil and NGL properties	16,664	385,964	83,318
Proceeds from sale of other property and equipment	—	15,882	—
Additions to deposits on property acquisitions	—	—	(43,577)
(Additions to) reductions in deposits on pipeline transportation	(41,811)	13,705	(123,087)
Additions to other property and equipment	(715)	(13,689)	(23,639)
Additions to other long-term assets	—	(21,041)	—
Net cash used in investing activities	$ (722,245)	$ (597,291)	$ (2,234,122)

Net Cash Provided by Financing Activities

Net cash flow provided by financing activities was comprised of the following:

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Financing activities:			
Proceeds from issuance of long-term debt, net	$ —	$ 922,210	$ 1,453,519
Proceeds from Note Payable to Member	177,000	250,000	—
Cash paid to purchase debt	(464,649)	(477,250)	—
Cash paid for debt issuance costs	(15,474)	(43,657)	(18,894)
Repayment of note payable to third party	(37,170)	—	—
Contributions from Member	1,154,719	135,000	614,840
Net cash provided by financing activities	$ 814,426	$ 786,303	$ 2,049,465

Contractual Obligations

The following table summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2016:

	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]	$ 1,389,599	$ —	$ 1,290,264	$ 99,335	$ —
Interest	251,530	143,900	107,630	—	—
Operating lease commitments[b]	1,906	623	1,283	—	—
Operating commitments[c]	10,699,086	360,110	1,176,932	1,171,629	7,990,415
Other	76	—	—	—	76
Total	$ 12,342,197	$ 504,633	$ 2,576,109	$ 1,270,964	$ 7,990,491

(a) Total principal amount of debt maturities, using the earliest repurchase date.

(b) See Note 9 of the notes to our consolidated financial statements included in this report for a description of our operating lease commitments.

(c) See Note 9 of the notes to our consolidated financial statements included in this report for a description of gathering, processing and transportation agreements and drilling contracts.

Commitments

Fixed Price Contracts

The Company from time to time enters into agreements to sell certain volumes of our natural gas and oil production at fixed prices. These contracts can be for one month or longer and effectively insulate the Company from commodity price decreases below the contracted fixed price while they are in place.

The contracted volumes are as follows:

	Natural Gas		Oil	
Period	Volumes (mmbtu/d)	Fixed Price $/mmbtu	Volumes (bbl/d)	Fixed Price $/bbl
January 2017	230,000	$ 3.06	1,500	$ 45.40
February 2017	150,000	$ 2.85	1,500	$ 45.40
March 2017	150,000	$ 2.85	1,500	$ 45.40
Q2 2017	50,000	$ 3.01	1,500	$ 45.40
Q3 2017	50,000	$ 3.01	—	$ —
Q4 2017	50,000	$ 3.01	—	$ —

Joint Venture Commitments

In 2013, the Company entered into a joint venture participation agreement with a third party 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 area of mutual interest 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. On February 19, 2016, the Company executed an amendment to extend the payment terms of carried costs from four years to five years. As of December 31, 2016 and 2015, the Company owed $103.3 million and $109.0 million, respectively, for this obligation. This obligation was discounted using an 11% discount rate, to reflect the imputation of interest, and is classified as an acquisition obligation in the consolidated balance sheets.

In 2014, the Company entered into a joint venture participation agreement with XTO Energy, Inc. (XTO) and Phillips Exploration, Inc. (Phillips). The participation agreement governs the funding, exploration, and development of the parties' jointly owned interests through the earliest to occur of either (a) January 29, 2024, (b) the point in time when all the lands covered by the leases have been made the subject of assignments, delivered to the respective receiving party or (c) the date at which the cumulative carry bank (Carry Bank) as defined in the agreement equals zero dollars. The initial agreement provided that the Company would acquire a 40% interest in non-operated wells upon certain defined acreage and a 95% interest in operated wells upon certain defined acreage. In exchange, the Company would carry 100% of XTO and Phillips' share of development costs until the Carry Bank is depleted. The Carry Bank was defined in the initial agreement as the positive amount, if any, by which (a) the sum of 40% of the aggregate allocated value of the XTO core leases (as defined in the agreement), and 95% of the aggregate allocated value of the XTO non-core leases (as defined in the agreement) exceeds (b) the sum of 60% of the aggregate allocated value of the Company's core leases and the amount of all carried costs previously paid by the Company.

On March 31, 2016, the Company and XTO amended the joint venture participation agreement such that the interest the Company would acquire would be reduced to a 5% interest in non-operated wells across a smaller amount of defined acreage and a 95% interest in operated wells across a larger amount of defined acreage, including an adjustment as to already earned acreage, which resulted in a reduction to the Carry Bank of approximately $80.0 million. The amendment revised certain contractual leasehold interests as defined in the agreement to provide XTO with a greater percentage interest in leases in a smaller XTO operated core area, with the Company obtaining an additional area to operate at a 95% working interest. As of December 31, 2016 and 2015, the Carry Bank was $79.7 million and $285.2 million, respectively. Participation in the joint venture is required by all parties while the Carry Bank has a positive balance. There are no required minimum payments associated with this agreement, as such the liability is not reflected in the contractual obligations table.

Results of Operations

General. For the year ended December 31, 2016, the Company had a net loss of $414.6 million on total sales of $280.7 million. This compares to a net loss of $664.6 million on total sales of $175.9 million for 2015 and a net loss of $326.2 million on total sales of $58.1 million for the year ended December 31, 2014. 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, oil and NGL properties, exploration expenses, litigation settlement expense and higher interest expense. The net loss in 2014 was driven by lower sales with associated start-up expenses.

Natural Gas, Oil and NGL Sales. During 2016, natural gas, oil and NGL sales were$280.7 million compared to $175.9 million in 2015 and $58.1 million in 2014. In 2016, the Company sold 137.5 mmcfe at a weighted average price of $2.67 per mcfe (excluding the effect of derivatives), compared to 56.0 mmcfe sold in 2015 for a weighted average price of $3.17 per mcfe (excluding the effect of derivatives) and 12.8 mmcfe sold in 2014 for a weighted average price of $4.54 per mcfe (excluding the effect of derivatives). The $189.2 million increase in sales (excluding the effect of derivatives) in 2016 compared to 2015 was driven by a 145% production increase which more than offset the decreases in natural gas and oil average sales prices from 2015. The $119.8 million increase in sales (excluding the effect of derivatives) from 2014 to 2015 was driven by a 338% production increase that more than offset the decrease in natural gas, oil and NGL average sales prices from 2014.

Our average prices received for natural gas per mcf (excluding the effect of derivatives) were $2.39, $2.62 and $3.27 in 2016, 2015 and 2014, respectively. Average oil prices received per barrel (excluding the effect of derivatives) were $33.19, $36.60 and $68.89 in 2016, 2015 and 2014, respectively. Average NGL prices received per barrel (excluding the effect of derivatives) were $14.23, $12.20 and $35.37 in 2016, 2015 and 2014, respectively.

Losses from our natural gas and oil derivatives resulted in a net decrease in natural gas, oil and NGL sales of $86.4 million and $2.0 million in 2016 and 2015, respectively.

A change in natural gas, oil and NGL prices has a significant impact on our sales and cash flows. Assuming our 2016 production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in 2016 sales and cash flows of approximately $2 million, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2016 sales and cash flows of approximately $11 million and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease in 2016 sales and cash flows of approximately $3.0 million.

Natural Gas, Oil and NGL Production Expenses. Production expenses were $24.1 million in 2016, compared to $21.1 million in 2015 and $6.8 million in 2014. On a unit-of-production basis, production expenses were $0.18 per mcfe in 2016 compared to $0.38 per mcfe in 2015 and $0.53 per mcfe in 2014. The per unit decreases in 2016 and 2015 were primarily the result of operating efficiencies.

Natural Gas, Oil and NGL Gathering, Processing and Transportation Expenses. Natural gas, oil and NGL gathering, processing and transportation expenses were $186.3 million in 2016 compared to $87.0 million in 2015 and $19.7 million in 2014. On a unit-of-production basis, gathering, processing and transportation expenses were $1.36 per mcfe in 2016 compared to $1.55 per mcfe in 2015 and $1.54 per mcfe in 2014. The $99.3 million increase from 2015 to 2016 was the result of increased production in 2016. The $67.3 million increase from 2014 to 2015 was the result of increased production in 2015.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $7.6 million in 2016 compared to $2.5 million in 2015 and $0.4 million in 2014. On a unit-of-production basis, production and ad valorem taxes were $0.05 per mcfe in 2016 compared to $0.04 per mcfe in 2015 and $0.03 per mcfe in 2014. In general, production taxes are calculated using volume based formulas that produce higher absolute costs as production increases. The increases in per unit costs from 2014 to 2015 and 2016 were attributable to increases in ad valorem taxes as additional producing wells came online over these years.

Exploration Expenses. Exploration expenses for 2016 were $270.0 million compared to $85.4 million in 2015 and $23.0 million in 2014. The Company impaired $252.8 million of individually insignificant unproved natural gas and oil properties in 2016 and $70.0 million in 2015. The Company also had rig and other standby charges of $11.9 million and $12.9 million in 2016 and 2015, respectively.

General and Administrative Expenses, Including Related Party. General and administrative expenses, including related-party expenses, were $38.4 million in 2016, $76.8 million in 2015 and $123.9 million in 2014, or $0.28, $1.37 and $9.68 per mcfe, respectively. The absolute and per unit expense decrease in 2016 and 2015 was primarily due to reduced overhead as a result of the termination of the management service agreement with AEU Services, LLC (AEU MSA) in late 2015 and increased production in both 2015 and 2016.

Incentive Units Expense. Incentive units expense was $0.7 million in 2016, $(5.2) million in 2015 and $39.5 million in 2014, or $0.00, $(0.09) and $3.09 per mcfe, respectively. The absolute and per unit expense decrease in 2016 and 2015 was primarily due to a decline in the fair value of vested incentive units as of December 31, 2016 and 2015, respectively.

Litigation Settlement Expense (Benefit). 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 credit to this accrual of $4.1 million for the contingent cash payments and paid the accrued $6.2 million which settled all previously recorded liabilities associated with this litigation.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $229.0 million, $133.4 million and $21.2 million in 2016, 2015 and 2014, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $1.67, $2.38 and $1.66 in 2016, 2015 and 2014, respectively. The per unit decrease in 2016 was the result of an increase in total proved reserves. The per unit increase in 2015 was primarily the result of the divestiture of certain proved natural gas, oil and NGL properties and the decrease in proved reserves due to economic conditions.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $1.9 million in 2016 compared to $0.7 million in 2015 and $0.3 million in 2014. On a unit-of-production basis, depreciation and amortization of other assets was $0.01 per mcfe in 2016 compared to $0.01 per mcfe in 2015 and $0.02 per mcfe in 2014. 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 type assets.

Loss on Divestiture of Natural Gas, Oil and NGL Properties. In 2015, the Company sold acreage, gas gathering assets and assigned certain pipeline transportation commitments in a series of transactions, for proceeds of $405.0 million resulting in a loss on divestiture of $205.6 million.

Interest Expense. Interest expense was $142.2 million in 2016 compared to $311.5 million in 2015 and $184.9 million in 2014, detailed as follows along with average borrowings:

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Interest expense on ARU Second Lien Term Loans	$ 162,410	$ 145,498	$ 90,399
Interest expense on ARU Convertible Notes	10,754	29,601	25,715
Interest expense on ARU Junior Lien	94,912	47,049	—
Interest expense on Note Payable to Member	54,067	24,670	—
Interest expense on pipeline commitments	4,209	968	—
Interest expense on Credit Facilities	72	1,931	—
Capitalized interest	(223,650)	(35,524)	(6,446)
Amortization of debt discount and issuance costs	39,451	97,330	75,202
Total interest expense, net	$ 142,225	$ 311,523	$ 184,870
Average ARU Second Lien Term Loans borrowings	$ 1,280,805	$ 1,149,291	$ 810,027
Average ARU Convertible Notes borrowings	$ 279,382	$ 847,752	$ 735,616
Average ARU Junior Lien borrowings	$ 587,459	$ 277,632	$ —
Average Note Payable to Member borrowings	$ 317,747	$ 145,183	$ —
Average Credit Facilities borrowings	$ —	$ 41,871	$ —

The decrease in 2016 interest expense was primarily due to capitalized interest expense of $223.7 million as a result of increased activity related to certain of our unproved properties.

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 ARU Convertible Notes in February 2016.

The increase in interest expense from 2014 to 2015 was mainly attributable to increases in the average principal balances outstanding under our ARU Second Lien Term Loans in 2015 compared to 2014, as well as, entering into the ARU Junior Lien and both the credit facility and the Note Payable to Member in 2015, partially offset by higher capitalized interest.

Acquisition Obligation Accretion Expense. Acquisition obligation accretion expense for the year ended December 31, 2016 was $10.1 million compared to $17.1 million in 2015 and $18.2 million in 2014. This obligation relates to the carried interest from certain asset acquisitions that require ARU to pay the seller's retained share of development costs for certain wells and other development operations that occur within an area of mutual interest as defined in the agreement. This obligation was discounted using an 11% discount rate for the years ended December 31, 2016, 2015 and 2014, to reflect the imputation of interest.

Change in Fair value of Embedded Derivative. The change in fair value of the embedded derivative in the ARU Convertible Notes issued in 2014 resulted in a $3.6 million gain for the year ended December 31, 2016, compared to a gain of $211.6 million in 2015 and $16.4 million in 2014. In general, increases in the business enterprise value, the probability of early exit, expected volatility, remaining time to maturity and the credit spread between the ARU Convertible Notes and the risk-free rate would increase the value of the embedded derivative liability. Alternatively, decreases in these factors, including a decrease in the outstanding principal amount of ARU Convertible Notes, would decrease the value of the embedded derivative liability.

Gains (Losses) on Purchases or Exchanges of Debt. The Company recognized a gain on purchases or exchanges of debt for the year ended December 31, 2016 of $207.5 million, consisting primarily of a $306.8 million gain associated with the exchange offer of the ARU Convertible Notes in February 2016, partially offset by a $4.7 million loss on the redemption of the New ARU Convertible Notes in April 2016 and a $97.3 million loss on the purchase of ARU Junior Lien in November 2016. For the year ended December 31, 2015, the Company recognized a loss on purchase or exchange of debt of $25.8 million, consisting of a $21.7 million loss in connection with the retirement of $277.3 million of the ARU Convertible Notes and a $4.1 million loss in connection with the retirement of the Company's previous $200.0 million credit facility in June 2015.

Gain on Bargain Purchase. In June 2014, the Company acquired leasehold acreage and certain producing properties in the Utica Shale in Ohio from a third party for approximately $182.1 million in cash. The Company recognized a gain on bargain purchase for the year ended December 31, 2014 of $36.1 million as a result of the excess of net assets acquired over consideration paid. We were able to acquire the assets for less than the estimated fair value as a result of further development costs paid by the seller after the purchase price was negotiated but before the closing of the acquisition.

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 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.

Counterparty 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:

	Years Ended December 31,		
	2016	**2015**	**2014**
Tenaska Marketing Ventures	47%	37%	19%
Marathon Petroleum Company, L.P.	16%	36%	18%
Vineyard Oil and Gas Company	—	5%	20%

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.

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.

Commodity Demand and Price Risk

Our primary market risk exposure is in the price we receive for our natural gas, oil and NGL production. 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 production will depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price. The demand for natural gas, oil and NGL is susceptible to volatility related to, among other factors, the level of global economic activity and may also fluctuate depending on the performance of specific industries. 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 we expect to produce.

To mitigate our exposure to adverse commodity price changes, we have periodically entered into commodity derivative instruments. The Company does not enter into commodity derivative instruments for speculative or trading purposes. Basis swaps may be periodically used to fix or float the differential between product prices at one market location versus another. Under the terms of the swaps, 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 expected future production. The sold call establishes the maximum price that the Company will receive for contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes.

The following table sets forth the volumes per day associated with the Company's outstanding natural gas derivative contracts as of December 31, 2016 and the weighted average natural gas prices for those contracts:

	Volume (mmbtu/d)	Weighted Average Price		
		Swap fixed price	Sold call strike price	Purchased put strike price
Natural gas:		($/mmbtu)		
Swaps:				
Q1 2017	191,000	$ 3.15		
Q2 2017	343,000	$ 3.01		
Q3 2017	320,000	$ 3.00		
Q4 2017	271,000	$ 3.09		
Q1 2018	209,000	$ 3.19		
Q2 2018	110,000	$ 2.90		
Q3 2018	110,000	$ 2.90		
Q4 2018	110,000	$ 2.93		
Two-way collars:				
Q1 2017	105,000		$ 3.46	$ 2.86
Q2 2017	7,500		$ 2.96	$ 2.48
Q3 2017	7,500		$ 2.96	$ 2.48
Q4 2017	2,500		$ 2.96	$ 2.48
Call options:				
Q1 2017	50,000		$ 3.25	
Q2 2017	50,000		$ 3.25	
Q3 2017	50,000		$ 3.25	
Q4 2017	50,000		$ 3.25	
Q1 2018	50,000		$ 3.25	
Q2 2018	50,000		$ 3.25	
Q3 2018	50,000		$ 3.25	
Q4 2018	50,000		$ 3.25	

The following table sets forth the volumes per day associated with the Company's outstanding oil derivative contracts as of December 31, 2016 and the prices for those contracts:

	Volume (bbl/d)	Weighted Average NYMEX ($/bbl)
Oil :		
Swaps:		
Q1 2017	6,800	$ 54.51
Q2 2017	4,800	$ 54.30
Q3 2017	4,800	$ 54.34
Q4 2017	3,800	$ 54.15
Q1 2018	3,000	$ 54.56
Q2 2018	2,700	$ 54.50
Q3 2018	2,500	$ 54.47
Q4 2018	2,600	$ 54.49

Interest Rate Risk

At December 31, 2016, the ARU Convertible Notes bore interest at a fixed rate of 4.5%. The ARU Second Lien Term Loans bore interest at a variable rate of 9.5% plus the greater of 1.5% or the 3-month LIBOR exposing us to interest rate risk. A 1.0% increase in the LIBOR for the year ended December 31, 2016 would have resulted in an estimated $7.7 million increase in interest expense on the ARU Second Lien Term Loans. We had no outstanding interest rate derivatives at December 31, 2016.

Report of Independent Auditors

To the Member and Management of Ascent Resources – Utica, LLC

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of member's equity and of cash flows present fairly, in all material respects, the financial position of Ascent Resources – Utica, LLC and its subsidiary as of December 31, 2016 and 2015, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States) 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 financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Other Matter

The consolidated financial statements of the Company for the year ended December 31, 2014 were audited by other auditors whose report, dated May 15, 2015, expressed an unqualified opinion on those statements.

PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
March 16, 2017

ASCENT RESOURCES – UTICA, LLC
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	($ in thousands)	
Current Assets:		
Cash and cash equivalents	$ 268,493	$ 84,187
Accounts receivable – natural gas, oil and NGL sales	92,400	35,072
Accounts receivable – joint interest and other	3,224	11,769
Short-term derivative asset	—	4,674
Other current assets	1,067	2,590
Total Current Assets	365,184	138,292
Property and Equipment:		
Natural gas, oil and NGL properties, based on successful efforts accounting	3,638,619	3,141,943
Other property and equipment	19,508	21,153
Less: accumulated depreciation, depletion and amortization	(370,955)	(140,199)
Property and Equipment, net	3,287,172	3,022,897
Other Assets:		
Deposits on pipeline transportation	151,193	109,382
Other long-term assets	6,959	21,041
Total Assets	$ 3,810,508	$ 3,291,612
Current Liabilities:		
Accounts payable	$ 39,675	$ 32,876
Revenue payable	34,167	19,426
Accrued interest	11,829	10,725
Short-term derivative liabilities	74,489	—
Acquisition obligation	47,121	5,440
Note payable	—	35,932
Other current liabilities	129,726	126,147
Total Current Liabilities	337,007	230,546
Long-Term Liabilities:		
Long-term debt, net	1,325,325	2,373,766
Note Payable to Member	—	274,670
Long-term derivative liabilities	19,414	7,746
Acquisition obligation	50,824	90,857
Other long-term liabilities	10,755	129
Total Long-Term Liabilities	1,406,318	2,747,168
Commitments and contingencies (Note 9)		
Member's Equity	2,067,183	313,898
Total Liabilities and Member's Equity	$ 3,810,508	$ 3,291,612

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

ASCENT RESOURCES – UTICA, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Revenues:			
Natural gas	$ 262,765	$ 100,311	$ 32,159
Oil	67,551	62,461	17,705
NGL	36,833	15,146	8,277
Commodity derivative loss	(86,434)	(2,005)	—
Total Revenues	280,715	175,913	58,141
Operating Expenses:			
Natural gas, oil and NGL production	24,061	21,119	6,798
Natural gas, oil and NGL gathering, processing and transportation	186,300	86,973	19,738
Production and ad valorem taxes	7,623	2,504	389
Exploration expenses	269,982	85,394	22,984
General and administrative expenses	6,686	15,875	62,274
General and administrative expenses – related party	31,727	60,949	61,581
Incentive units expense	733	(5,220)	39,517
Litigation settlement expense (benefit)	(4,147)	92,974	—
Impairment of other property and equipment	2,222	—	—
Natural gas, oil and NGL depreciation, depletion and amortization	229,038	133,410	21,185
Depreciation and amortization of other assets	1,864	660	310
Loss on divestiture of natural gas, oil and NGL properties	—	205,638	—
Total Operating Expenses	756,089	700,276	234,776
Loss From Operations	(475,374)	(524,363)	(176,635)
Other Income (Expense):			
Interest expense, net	(142,225)	(311,523)	(184,870)
Acquisition obligation accretion expense	(10,108)	(17,118)	(18,212)
Change in fair value of embedded derivative	3,616	211,593	16,412
Gains (losses) on purchases or exchanges of debt	207,470	(25,831)	—
Gain on bargain purchase	—	—	36,135
Other income	2,001	2,596	933
Total Other Income (Expense)	60,754	(140,283)	(149,602)
Net Loss	$ (414,620)	$ (664,646)	$ (326,237)

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

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

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Balance, beginning of period	$ 313,898	$ 848,833	$ 520,713
Contributions from Member - cash	1,154,719	135,000	614,840
Contributions from Member - non-cash issuance of Parent equity	508,170	—	—
Conversion of Note Payable to Member	505,736	—	—
Purchase of debt by Member	(745)	—	—
Incentive units expense	25	(5,289)	39,517
Net loss	(414,620)	(664,646)	(326,237)
Balance, end of period	$ 2,067,183	$ 313,898	$ 848,833

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

ASCENT RESOURCES – UTICA, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Cash Flows from Operating Activities:			
Net loss	$ (414,620)	$ (664,646)	$ (326,237)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	230,902	134,070	21,495
Impairment of other property and equipment	2,222	—	—
Change in fair value of commodity derivatives	90,831	3,072	—
Exploration expense	252,845	72,117	12,407
Incentive units expense	733	(5,220)	39,517
Interest expense	138,772	219,315	115,098
Acquisition obligation accretion expense	10,108	17,118	18,212
Change in fair value of embedded derivative	(3,616)	(211,593)	(16,412)
(Gains) losses on purchases or exchanges of debt	(208,137)	25,831	—
Litigation settlement expense (benefit)	(4,147)	92,974	—
Loss on divestiture of natural gas, oil and NGL properties	—	205,638	—
Gain on bargain purchase	—	—	(36,135)
Changes in assets and liabilities:			
Decrease (increase) in accounts receivable and other assets	(49,708)	3,165	(50,423)
(Decrease) increase in accounts payable, liabilities and other	45,940	(51,795)	71,899
Net Cash Provided by (Used In) Operating Activities	92,125	(159,954)	(150,579)
Cash Flows from Investing Activities:			
Drilling and completion costs	(268,082)	(760,435)	(205,070)
Acquisitions of proved and unproved natural gas, oil and NGL properties	(428,301)	(217,677)	(1,922,067)
Proceeds from divestitures of proved and unproved natural gas, oil and NGL properties	16,664	385,964	83,318
Proceeds from sale of other property and equipment	—	15,882	—
Additions to deposits on property acquisitions	—	—	(43,577)
(Additions to) reductions in deposits on pipeline transportation	(41,811)	13,705	(123,087)
Additions to other property and equipment	(715)	(13,689)	(23,639)
Additions to other long-term assets	—	(21,041)	—
Net Cash Used in Investing Activities	(722,245)	(597,291)	(2,234,122)
Cash Flows from Financing Activities:			
Proceeds from issuance of long-term debt, net	—	922,210	1,453,519
Proceeds from Note Payable to Member	177,000	250,000	—
Cash paid to purchase debt	(464,649)	(477,250)	—
Cash paid for debt issuance costs	(15,474)	(43,657)	(18,894)
Repayment of note payable to third party	(37,170)	—	—
Contributions from Member	1,154,719	135,000	614,840
Net Cash Provided by Financing Activities	814,426	786,303	2,049,465
Net Increase (Decrease) in Cash and Cash Equivalents	184,306	29,058	(335,236)
Cash and Cash Equivalents, Beginning of Period	84,187	55,129	390,365
Cash and Cash Equivalents, End of Period	$ 268,493	$ 84,187	$ 55,129

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

Supplemental disclosure of cash flow information:	Years Ended December 31,		
	2016	2015	2014
	($ in thousands)		
Interest paid, net of capitalized interest and interest paid in kind	$ —	$ 109,145	$ 47,498

Supplemental disclosures of significant non-cash investing and financing activities:			
Change in accrued capital expenditures	$ (24,058)	$ (47,985)	$ 114,444
Contributions from Member - non-cash issuance of Parent equity	$ 508,170	$ —	$ —
Equity conversion of Note Payable to Member	$ 505,736	$ —	$ —
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, LLC (the Company or ARU), an Oklahoma limited liability company, was formed on June 14, 2013, and is a wholly-owned subsidiary of Ascent Resources Utica Holdings, LLC (the Member). 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 Company was initially capitalized in September 2013 with contributions provided by The Energy & Minerals Group (EMG), First Reserve Corporation, other institutional investors and entities associated with the management of American Energy Partners, LP (AELP) (collectively, the Sponsors). The Member is not liable for the liabilities or other obligations of the Company. The Company will continue perpetually until terminated pursuant to statute or any provision of the Member's Limited Liability Company Agreement.

Effective December 31, 2014, the Member and the Company were reorganized and were contributed to Ascent Resources Operating, LLC (ARO), a subsidiary of Ascent Resources, LLC (the Parent). EMG controls the Parent as a result of the number of managers it can designate to the board of managers of our Parent. The Parent, a Delaware limited liability company, was formed on October 13, 2014, to effect the combination of the Company and its affiliate, Ascent Resources – Marcellus, LLC (ARM). Prior to the reorganization, EMG controlled the Company through the board of managers of the Member and its ownership interest in the Member.

The 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 subsidiary, ARU Finance Corporation. ARU Finance Corporation was incorporated in Delaware in January 2014 and has not undertaken any corporate action other than being a co-issuer of the convertible subordinated notes (the ARU Convertible Notes) and a party to the second lien term loan (ARU Second Lien Term Loans) and junior secured credit agreement (ARU Junior Lien). There are no intercompany balances and transactions requiring elimination upon consolidation. Certain prior period amounts have been reclassified to conform to current period classification.

Risks and Uncertainties

A substantial or extended decline in natural gas, oil and natural gas liquids (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. Substantial capital expenditures are required to replace reserves and sustain production. Other risks and uncertainties that could affect us in a low commodity price environment include, but are not limited to, counterparty credit risk, access to capital markets, regulatory risk and our ability to meet financial ratios and covenants in our debt agreements. Furthermore, our ability to generate positive operating cash flows in a low commodity price environment, sell assets, or take any other action to improve our liquidity is subject to risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control.

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 oil and natural gas reserves and their values, future production rates and future costs and expenses are the most significant of our 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, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in oil, natural gas or NGL prices could result in actual results differing significantly from our 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,		
	2016	**2015**	**2014**
Tenaska Marketing Ventures	47%	37%	19%
Marathon Petroleum Company, L.P.	16%	36%	18%
Vineyard Oil and Gas Company	—	5%	20%

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, 2016 and 2015 were $95.6 million and $46.8 million, respectively, and consist primarily of accrued natural gas, oil and NGL revenues receivable 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, Oil and NGL Properties

The Company uses the successful efforts method of accounting for natural gas, oil and NGL 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, oil and NGL 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, oil and NGL properties are reviewed for impairment on a field level basis whenever events and circumstances indicate a possible decline in the recoverability of the carrying value of such field. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value (typically determined using discounted future cash flows). No impairment of proved natural gas, oil and NGL properties was recorded for the years ended December 31, 2016, 2015 or 2014. 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, oil and NGL 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, 2016, 2015 and 2014, the Company recorded impairments of $252.8 million, $70.0 million and $12.4 million, respectively, to exploration expense related to individually insignificant non-producing natural gas and oil properties.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization of capitalized drilling and development costs of producing natural gas, oil and NGL properties are computed using the unit-of-production method on a field level basis, 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 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 five to seven years. The field office locations are 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, $0.7 million and $0.3 million for the years ended December 31, 2016, 2015, and 2014, respectively. 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, oil and NGL 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, oil and NGL properties and expensed through depletion of the asset. The accretion expense is recorded as a component of natural gas, oil and NGL depreciation, depletion and amortization 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 ARU Second Lien Term Loans, ARU Junior Lien and ARU Convertible Notes have been presented as a reduction to long-term debt in the consolidated balance sheets. The Company amortizes debt issuance costs related to the ARU Convertible Notes through the maturity date using the effective interest method. The Company amortizes debt issuance costs related to all other debt over the scheduled maturity period of the debt on a straight-line basis, which approximates 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, 2016 and 2015, the Company 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, 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, restricted cash, 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 recipient of the incentive units are employees of the Parent, the units are accounted for as liability-classified awards in accordance with ASC 718 *Stock Compensation*. Fair value of the employee incentive units is re-measured each reporting period until the awards are settled.

To the extent the recipient of the incentive units are non-employees of the Parent, 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.

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. The Company has entered into commodity derivative contracts with investment-grade rated counterparties.

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/rates as of the respective balance sheet dates. Cash settlements of our 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 statement of cash flows. All of our derivative instruments are subject to 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. Therefore, we net the value of our derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

We have established the fair value of our derivative instruments using 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 the Company's 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.

The Company has entered into International Swaps and Derivatives Association (ISDA) master agreements with its commodity derivative counterparties. The Company nets its commodity derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. See Note 5 for further discussion of our derivative instruments.

Income Taxes

The Company and Member are treated as disregarded entities 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 consolidated financial statements.

Financial statement benefits of a tax position are recognized only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the consolidated financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon the ultimate settlement with the relevant tax authority. At December 31, 2016 and 2015, the income tax position was assessed and it was determined that there were no uncertain tax positions.

Reclassifications

Certain reclassifications have been made to our consolidated financial statements for 2015 and 2014 to conform to the presentation used for the 2016 consolidated financial statements.

Adopted and Recently Issued Accounting Pronouncements

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. 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. On August 12, 2015, the FASB issued ASU 2015-14, which deferred the effective date of the new revenue standard by one year. The FASB will permit entities to adopt one year earlier if they choose (i.e., the original effective date). The revenue standard would be effective for annual and interim periods beginning after December 15, 2017. 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. The Company is currently evaluating the impact of this ASU on its consolidated financial statements.

In August 2014, the FASB issued ASU 2014-15, *Going Concern*, which is an update for Accounting Standards Codification Topic No. 205 *Presentation of Financial Statements*. This update requires management, for each annual and interim reporting period, to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the consolidated financial statements are issued. If management concludes that conditions or events raise substantial doubt about the entity's ability to continue as a going concern, certain disclosures are required to be made within the footnotes to the consolidated financial statements. The amendments in this update were effective for annual periods ending after December 15, 2016 and interim periods thereafter, with early adoption permitted. The Company adopted this update in the fourth quarter of 2016 resulting in no impact on our consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases*. 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. 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. The Company is currently evaluating the impact of this ASU on its consolidated financial statements.

In March 2016, the FASB issued ASU 2016-06, *Contingent Put and Call Options in Debt Instruments*. The new standard will result in fewer put or call options embedded in debt instruments qualifying for separate derivative accounting because companies will not be required to assess whether the contingent event, such as change in control or an IPO, is related to interest rates or credit risks. This standard is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. The Company has adopted this standard and does not anticipate it will have a material effect on its consolidated financial statements and disclosures.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*. This guidance addresses eight specific cash flow issues. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In October 2016, the FASB issued ASU No. 2016-17, *Consolidation: Interests Held through Related Parties That Are Under Common Control*. This guidance provides an amendment to the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In December 2016, the FASB issued ASU No. 2016-20, *Technical Corrections and Improvements to Topic 606*, *Revenue from Contracts with Customers*. This guidance updates narrow aspects of the guidance issued in Update 2014-09. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact of this ASU on its consolidated financial statements.

In January 2017, the FASB issued Update 2017-01 - *Business Combinations (Topic 805)*. 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 periods beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2019. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

Subsequent Events

The Company evaluated its December 31, 2016 consolidated financial statements for subsequent events through March 16, 2017, the date the consolidated financial statements were available to be issued, and such events are noted herein.

2. Acquisitions and Divestitures

Acquisitions

In August 2014, the Company acquired leasehold acreage and certain producing properties in the Utica Shale in Ohio from third parties for approximately $397.9 million (Utica Acquisition). Through subsequent closings, the Company acquired additional acreage for approximately $40.6 million in 2015. The consideration paid included the issuance of $250.0 million of the ARU Convertible Notes at a discount for $244.3 million and cash on hand of $194.2 million. The Utica Acquisition was accounted for under the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized in the consolidated balance sheet at their respective fair values as of the acquisition date. The following table summarizes the allocation of the purchase price to the fair value of the assets acquired and liabilities assumed as of the acquisition dates:

		($ in thousands)
Proved natural gas, oil and NGL properties	$	79,183
Unproved natural gas, oil and NGL properties		343,108
Other property and equipment		16,289
Asset retirement obligations		(30)
Other liabilities		(67)
Total Purchase Price	$	438,483

For the year ended December 31, 2014, the Company incurred approximately $3.0 million of transaction costs related to the Utica Acquisition, which are included in general and administrative expense in the consolidated statements of operations. Included in this amount was $1.0 million related to a transition services agreement with the sellers to provide services for the acquired properties through November 30, 2014.

The following unaudited pro forma consolidated financial information for the year ended December 31, 2014 has been prepared as if the Utica Acquisition had occurred on January 1, 2013. The unaudited pro forma financial information was derived from the historical consolidated statement of operations of the Company and the historical financial statements of the acquired third parties. The unaudited pro forma financial information does not purport to be indicative of the results of operations that would have occurred had the acquisition and related financing occurred on the basis assumed above, nor is such information indicative of the Company's expected future results of operations.

		Year Ended December 31, 2014 (Unaudited) ($ in thousands)
Revenues	$	70,873
Loss from operations	$	(169,509)
Net loss	$	(327,164)

In June 2014, the Company acquired leasehold acreage and certain producing properties in the Utica Shale in Ohio from a third party for approximately $182.1 million in cash. The acquisition was accounted for under the acquisition method of accounting. A bargain purchase gain resulted from the excess of net assets acquired over consideration paid in the acquisition. The Company was able to acquire the assets for less than the estimated fair value of the net assets as a result of further development costs paid by the seller after the purchase price was negotiated but before the closing of the acquisition. The following table summarizes the allocation of the purchase price to the fair value of the assets acquired and liabilities assumed as of the acquisition date:

	($ in thousands)	
Proved natural gas, oil and NGL properties	$	179,152
Unproved natural gas, oil and NGL properties		36,704
Other property and equipment		2,360
Asset retirement obligations		(9)
Bargain purchase gain		(36,135)
Total Purchase Price	$	182,072

In a series of transactions, during the year ended December 31, 2014, the Company acquired unproved leasehold interests in the Utica Shale in Ohio from a third party for $905.8 million. In July 2015, the Company completed a subsequent closing for an aggregate purchase price of $110.1 million, of which $72.9 million ($50.0 million deposit included) was paid in cash and a $37.2 million promissory note was issued by the Company to the third party. As there was no stated interest rate, the Company imputed interest at 10.8%, which resulted in a $3.6 million discount that was accreted over the life of the note. During 2016, the $37.2 million promissory note was paid in full.

Divestitures

In June 2015, the Company sold acreage, gas gathering assets and assigned certain pipeline transportation commitments to a third party in a series of transactions, for an aggregate purchase price of $405.0 million as follows:

- The Company sold approximately 6,000 net acres located in Belmont and Jefferson Counties, Ohio and assigned certain pipeline transportation commitments for a purchase price of approximately $68.2 million,
- The Company sold approximately 24,000 undeveloped and 3,000 developed net acres located in Monroe County, Ohio, a gas gathering system and assigned certain pipeline transportation commitments for a purchase price of approximately $318.6 million and,
- The Company sold approximately 2,000 undeveloped net acres in Monroe County for a purchase price of approximately $18.2 million.

Overall, the Company recognized an aggregate loss of $205.6 million in connection with these transactions. In 2015, the Company recognized revenues of $5.2 million and direct operating expenses of $1.3 million associated with these divested properties. For the year ended December 31, 2014, the Company recognized revenues of $11.7 million and minimal direct operating expenses for the same divested properties.

3. Property and Equipment

Net property and equipment includes the following:

	December 31, 2016	December 31, 2015
	($ in thousands)	
Proved natural gas, oil and NGL properties	$ 2,094,137	$ 1,641,276
Unproved natural gas, oil and NGL properties	1,544,482	1,500,667
Other property and equipment	19,508	21,153
Total property and equipment	3,658,127	3,163,096
Accumulated depreciation, depletion and amortization	(370,955)	(140,199)
Net property and equipment	$ 3,287,172	$ 3,022,897

At December 31, 2016 and 2015, the Company did not have a significant amount of capitalized well costs that were pending determination of proved reserves.

The Company's asset retirement obligations relate to future plugging and abandonment costs on its natural gas, oil and NGL properties. The liability is included in other long-term liabilities in the consolidated balance sheets. The following table summarizes the changes in the Company's future asset retirement obligations for the periods presented:

	Years Ended December 31, 2016	Years Ended December 31, 2015
	($ in thousands)	
Asset retirement obligations, beginning of period	$ 60	$ 56
Additions	8	2
Settlements and disposals	—	—
Accretion expense	11	2
Total asset retirement obligations, end of period	$ 79	$ 60

4. Long-Term Debt

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

	December 31, 2016	December 31, 2015
	($ in thousands)	
ARU Second Lien Term Loans due 2018[a]	$ 1,290,263	$ 1,270,906
ARU Convertible Notes due 2021[b]	82,870	760,003
ARU Junior Lien due 2019[c]	—	526,463
Credit Facilities	—	—
Net unamortized debt issuance costs	(40,169)	(57,774)
Net unamortized debt discounts	(7,639)	(125,832)
Total Long-Term Debt, net	$ 1,325,325	$ 2,373,766

(a) The nominal interest rate was 11% and 13% as of December 31, 2016 and 2015, respectively.

(b) The nominal interest rate was 4.5% and 3.5% as of December 31, 2016 and 2015, respectively.

(c) The nominal interest rate was 15% at the time of its retirement in November 2016 and 17.5% as of December 31, 2015.

ARU Second Lien Term Loans

In September 2013, the Company and ARU Finance Corporation entered into a $450.0 million, five-year second lien term loan with a maturity date of September 30, 2018. The proceeds of the ARU Second Lien Term Loans were used for the acquisition of natural gas and oil properties. In February 2014, the ARU Second Lien Term Loans were amended and restated (the First Amendment) to provide an incremental loan amount of $500.0 million. The proceeds of the First Amendment were used for the acquisition of natural gas and oil properties and for general corporate purposes. In June 2015, the ARU Second Lien Term Loans were amended and restated (the Second Amendment) to provide an incremental loan amount of $250.0 million. The proceeds from the Second Amendment were used to repay $200.0 million outstanding under the Company's 2015 credit facility and for general corporate purposes.

The ARU Second Lien Term Loans are collateralized by ARU's natural gas, oil and NGL proved reserves and all other assets of ARU.

In November 2016, the Company received equity contributions from the Member of approximately $654.5 million. The additional equity contributions, combined with previously received equity contributions, surpassed a defined Additional Equity Contribution threshold within the ARU 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 has the ability to elect to pay up to 2.0% of interest in kind. Previously, the ARU 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. Interest payments are due the last day of the interest period, if shorter than three months, or every three months.

ARU amortizes the discount on the ARU Second Lien Term Loans to interest expense through the maturity date using the effective interest method.

The ARU Second Lien Term Loans contain 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, consolidate or merge, enter into transactions with affiliates or dispose of assets. At December 31, 2016 and 2015, ARU was in compliance with the covenants of the ARU Second Lien Term Loans.

During the first quarter of 2016, the ARU Second Lien Term Loans were further amended in connection with the exchange offer as further described below under *ARU Convertible Notes*. The financial maintenance covenants were amended as follows for 2016: ARU must have cash, cash equivalents or availability under any credit facility of at least $50.0 million at the end of each calendar month beginning February 29, 2016 and ending on June 30, 2016 and $100.0 million at the end of each calendar month beginning July 1, 2016 and ending on December 31, 2016. In 2016, there were no debt to EBITDAX maintenance covenants. The financial maintenance covenants were amended as follows for 2017: ARU's total debt to EBITDAX be no greater than 7.75 to 1.00 for the quarters ending March 31, 2017, June 30, 2017, and September 30, 2017; 7.50 to 1.00 for the quarter ending December 31, 2017; 7.00 to 1.00 for the quarter ending March 31, 2018; 6.50 to 1.00 for the quarter ending June 30, 2018; and 6.00 to 1.00 for each fiscal quarter ending on or after September 30, 2018. For purposes of this covenant, total debt excludes indebtedness under the ARU Convertible Notes.

ARU Convertible Notes

In February 2014, ARU and ARU Finance Corporation co-issued $750.0 million of the ARU Convertible Notes pursuant to an indenture (the Indenture) by and between ARU and Wilmington Trust, National Association, as the trustee, 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. On August 4, 2014, ARU issued an additional $250.0 million of the ARU Convertible Notes at par to fund the Utica Acquisition described in Note 2. ARU identified certain embedded features in the ARU Convertible Notes that were required to be bifurcated and accounted for as a derivative. The derivative financial instruments were recorded at fair value as of the issuance date of the ARU Convertible Notes and are remeasured to fair value as of each subsequent balance sheet date and are classified in long-term debt in the consolidated balance sheets. See Note 7 for further discussion of the fair value of the embedded derivative.

The ARU Convertible Notes are due on March 1, 2021. Interest was payable at an annual rate of 3.5% and may be paid in cash or in kind semi-annually in arrears on March 1 and September 1 of each year. The interest rate escalates by 0.50% on each interest payment date, beginning March 1, 2016, if a preliminary prospectus relating to a qualified initial public offering (Qualified PO) has not been filed under the Securities Act by such date, subject to a maximum interest rate of 6.50% per annum. We have elected to pay interest in kind on each interest payment date since September 2015 and the current interest rate, as of March 1, 2017, is 5.0%. Upon maturity, unless earlier paid or converted, ARU will be required to redeem the ARU Convertible Notes at 153.8% of the stated value, which represents repayment of principal plus a premium. ARU amortizes the discount on the ARU Convertible Notes to interest expense through the maturity date using the effective interest method.

Conversion of the ARU 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 ARU 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% to 65% dependent upon the passage of time from the issuance date of the ARU 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 ARU 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 ARU, 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 ARU 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 is the equity value of such Qualified PO Issuer and the denominator is the equity value of ARU.
    b. The common shares of the Qualified PO Issuer immediately prior to considering the effects of conversion.

The ARU Convertible Notes also provide for cash redemption upon a change in control event at the option of the holders at a premium ranging from 125.0% to 153.8% of the face value of the ARU Convertible Notes, depending on the change of control date relative to the date issued. The ARU 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, ARU has the option to redeem all of the ARU Convertible Notes that were not converted at a price equal to 100.0% of the principal of the ARU Convertible Notes to be redeemed, plus accrued and unpaid interest, if any.

In June 2015, the Company purchased $277.3 million of the ARU Convertible Notes with proceeds from the ARU Junior Lien, which resulted in a $21.7 million loss on the purchase of debt.

In January 2016, ARU and ARU Finance Corporation announced an offer to exchange (Exchange Offer) the outstanding ARU Convertible Notes for newly issued 3.50% ARU Convertible Notes due 2021 (New ARU Convertible Notes) and incremental ARU Junior Lien due 2019. In exchange for each $1,000 principal amount of the ARU 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 ARU Junior Lien plus an additional principal amount of ARU Junior Lien corresponding to 5% of any accrued and unpaid interest on the ARU Convertible Notes and (ii) $950 principal amount of the New ARU Convertible Notes plus an additional principal amount of New ARU Convertible Notes corresponding to 95% of any accrued and unpaid interest on the ARU Convertible Notes. The Exchange Offer closed on February 24, 2016, with $661.9 million in aggregate principal amount of the ARU Convertible Notes, representing 90% of the outstanding principal amount of the ARU 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 ARU 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 debt issuance costs and discounts associated with the ARU Convertible Notes. As of December 31, 2016, $76.3 million in aggregate principal amount of the ARU Convertible Notes remained outstanding, which will be accreted to a maturity date value of $117.4 million over the scheduled maturity period of the debt.

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

ARU Junior Lien

In June 2015, the Company and ARU Finance Corporation entered into the $477.3 million ARU Junior Lien with a maturity date of July 1, 2019. A portion of the proceeds were used to repay $277.3 million of the ARU Convertible Notes, and the remainder was used for general corporate purposes.

During the first quarter of 2016, the ARU Junior Lien was amended in connection with the Exchange Offer as further described above under *ARU Convertible Notes*. The amendment provided for the interest rate to decrease from 17.5% to 15.0% upon completion of the Qualified Equity Sale, upon which $500.0 million in equity was contributed to ARU on March 24, 2016. Also, in conjunction with the Exchange Offer, $33.7 million in aggregate principal of ARU Junior Lien, with a discount of $26.9 million, were issued.

In November 2016, the Company purchased and retired all of the $789.3 million of outstanding principal and accrued and unpaid interest of the ARU Junior Lien. In connection with the purchase, (a) the Company paid cash of approximately $479.5 million, funded by cash proceeds from equity contributions from the Member, and (b) approximately $271.0 million of equity was issued by our Parent. This transaction resulted in a $97.3 million loss on the purchase of the ARU Junior Lien, including the write-off of unamortized debt issuance costs and discounts.

Interest on the ARU Junior Lien was paid in kind quarterly and was compounded and added to the unpaid principal amount of the loan.

Credit Facilities

2016 Credit Facility. In September 2016, the Company entered into a credit facility that is collateralized by first lien mortgages on all of ARU's natural gas, oil and NGL properties (2016 Credit Facility). The 2016 Credit Facility has a borrowing base of $100.0 million and matures on June 30, 2018. The maturity date shall be automatically extended to June 25, 2019 if (a) no later than September 30, 2017 the Company provides evidence that the maturity date of 100% of the outstanding ARU Second Lien Term Loans and all other qualified indebtedness has been extended beyond September 26, 2019, or all such debt has been fully repaid or converted into or exchanged for equity interests and (b) on the date the Company provides such evidence of extension or repayment, no event of default exists.

Borrowings under the 2016 Credit Facility may be designated as either alternative base rate (ABR) loans or eurodollar loans. ABR loans bear interest at the greatest of the prime rate, the federal funds effective rate plus 0.50%, or the adjusted LIBOR plus 1.00%, plus, in each case, the applicable margin, as defined in the agreement, and is paid quarterly. Eurodollar loans bear interest at the adjusted LIBOR plus the applicable margin and is paid on the last day of the interest period, if shorter than three months, or every three months. There were no outstanding borrowings or letters of credit issued under the 2016 Credit Facility as of December 31, 2016. As of March 16, 2017, there was one $16.9 million letter of credit outstanding, which reduced our availability under the facility to $83.1 million.

The 2016 Credit Facility contains 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, consolidate or merge, enter into transactions with affiliates or dispose of assets.

The 2016 Credit Facility also contains certain financial maintenance covenants. The Company must maintain an EBITDAX to interest expense ratio of 1.00 to 1.00 for the quarter ending March 31, 2017; 1.25 to 1.00 for the quarter ending June 30, 2017, and 1.50 to 1.00 for each fiscal quarter ending on or after September 30, 2017. The Company must also maintain a first lien debt to EBITDAX ratio not to exceed 1.50 to 1.00 for the quarters ending March 31, 2017 and June 30, 2017; 2.00 to 1.00 for the quarters ending September 30, 2017 and December 31, 2017; and 2.50 to 1.00 for each fiscal quarter ending on or after March 31, 2018. For purposes of this covenant, total debt only includes indebtedness under the credit facility. At December 31, 2016, the Company was in compliance with the covenants of the 2016 Credit Facility.

As of December 31, 2016, the Company had incurred $7.0 million in unamortized debt issuance costs associated with the 2016 Credit Facility, which are presented as other long-term assets in the consolidated balance sheets.

2015 Credit Facility. In February 2015, ARU entered into a credit facility (2015 Credit Facility) that was collateralized by ARU's natural gas and oil properties. The 2015 Credit Facility had an initial borrowing base of $150.0 million, which was increased by the lenders to $200.0 million in May 2015. In June 2015, ARU repaid in full and retired the 2015 Credit Facility with the proceeds from the Second Amendment to the ARU Second Lien Term Loans, resulting in a loss on purchase of debt of $4.1 million during the year ended December 31, 2015.

Interest Expense

Interest expense was comprised of the following:

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Interest expense[(a)]	$ 272,357	$ 225,047	$ 116,114
Interest expense - related party[(b)]	54,067	24,670	—
Capitalized interest	(223,650)	(35,524)	(6,446)
Long-term debt accretion expense[(c)]	24,505	84,329	68,336
Deferred debt issuance cost amortization	14,946	13,001	6,866
Total interest expense, net	$ 142,225	$ 311,523	$ 184,870

(a) Includes interest paid in kind of $107.7 million, $97.2 million and $39.9 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(b) All interest was paid in kind, compounded and added to the unpaid principal amount of the Note Payable to Member on a quarterly basis. See Note 8 for more information.

(c) Includes amortization of the discount on the ARU Convertible Notes of $22.3 million, $81.3 million and $68.3 million for the years ended December 31, 2016, 2015 and 2014, respectively.

5. Commodity Derivative Instruments

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. The Company does not enter into commodity derivative instruments for speculative or trading purposes. Basis swaps may be periodically used to fix or float the differential between product prices at one market location versus another. Under the terms of the swaps, 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 expected future production. The sold call establishes the maximum price that the Company will receive for contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes.

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. The Company has entered into commodity derivative contracts with only investment-grade rated counterparties.

The following table sets forth the volumes per day associated with the Company's outstanding natural gas derivative contracts as of December 31, 2016 and the weighted average natural gas prices for those contracts:

		Weighted Average Prices		
	Volume (mmbtu/d)	Swap fixed price	Sold call strike price	Purchased put strike price
			($/mmbtu)	
Natural gas:				
Swaps:				
Q1 2017	191,000	$ 3.15		
Q2 2017	343,000	$ 3.01		
Q3 2017	320,000	$ 3.00		
Q4 2017	271,000	$ 3.09		
Q1 2018	209,000	$ 3.19		
Q2 2018	110,000	$ 2.90		
Q3 2018	110,000	$ 2.90		
Q4 2018	110,000	$ 2.93		
Two-way collars				
Q1 2017	105,000		$ 3.46	$ 2.86
Q2 2017	7,500		$ 2.96	$ 2.48
Q3 2017	7,500		$ 2.96	$ 2.48
Q4 2017	2,500		$ 2.96	$ 2.48
Call options:				
Q1 2017	50,000		$ 3.25	
Q2 2017	50,000		$ 3.25	
Q3 2017	50,000		$ 3.25	
Q4 2017	50,000		$ 3.25	
Q1 2018	50,000		$ 3.25	
Q2 2018	50,000		$ 3.25	
Q3 2018	50,000		$ 3.25	
Q4 2018	50,000		$ 3.25	

The following table sets forth the volumes per day associated with the Company's outstanding oil derivative contracts as of December 31, 2016 and the prices for those contracts:

	Volume (bbl/d)	Weighted Average NYMEX ($/bbl)
Oil :		
Swaps:		
Q1 2017	6,800	$ 54.51
Q2 2017	4,800	$ 54.30
Q3 2017	4,800	$ 54.34
Q4 2017	3,800	$ 54.15
Q1 2018	3,000	$ 54.56
Q2 2018	2,700	$ 54.50
Q3 2018	2,500	$ 54.47
Q4 2018	2,600	$ 54.49

The following tables summarize the classification and fair value amounts of all commodity derivative instruments in the consolidated balance sheet as of December 31, 2016 and 2015, as well as the gross recognized derivative assets and liabilities and amounts offset in the balance sheet.

	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 liabilities:				
Natural gas and oil commodity derivatives	Short-term derivative liability	$ (74,489)	$ —	$ (74,489)
Natural gas and oil commodity derivatives	Long-term derivative liability	$ (19,414)	$ —	$ (19,414)

	Balance Sheet Classification	December 31, 2015 Gross Recognized Fair Value	Amounts Netted in Balance Sheet	Net Recognized Fair Value in Balance Sheet
		($ in thousands)		
Derivative assets:				
Natural gas commodity derivatives	Short-term derivative asset	$ 4,674	$ —	$ 4,674
Derivative liabilities:				
Natural gas commodity derivatives	Long-term derivative liability	$ (7,746)	$ —	$ (7,746)

The following table summarizes the effects of commodity derivative instruments in the consolidated statements of operations for the years ended December 31, 2016 and 2015. The Company had no commodity derivative instruments in 2014.

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

6. Incentive Units

Overview

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.

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

To the extent the recipient of the incentive units are non-employees of the Parent, 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.

All fair value measurements related to the incentive units were determined using option pricing models. The fair value of the incentive units has been classified 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 incentive units as of December 31, 2016, were as follows:

Ascent Resources, LLC business enterprise value	$2,100 million
Probability of initial public offering or change in control	5% – 50% with a total of 100% over three years
Expected volatility	99% – 138%
Expected term	Between one and three years
Risk-free rate	0.9% – 1.6%

A portion of the incentive unit expense recognized by the Parent under each plan is allocated to the Company each reporting period. The amounts recognized for the years ended December 31, 2016 and 2015 did not have a material effect on our consolidated statement of operations. The amounts recognized for the year ended December 31, 2014 are described below.

2013 Member Incentive Units

Prior to the contribution of the Member to the Parent, the Member issued incentive units to certain individuals and consultants that provided services during 2013 and 2014 to the Company under the management services agreement with AEU Services, LLC (AEU MSA). See Note 8 for further discussion of these agreements.

On September 27, 2013, 25% of the Member incentive units immediately vested, resulting in the fair value associated with these units being immediately recognized as incentive unit expense in the statement of operations. The remaining incentive units were scheduled to vest ratably over a three year period beginning on October 1, 2013.

On December 31, 2014, the Member incentive units were cancelled and replaced by incentive units issued by the Parent at a ratio of 1 to 0.777, which was accounted for as a modification. The impact of the modification to the Company was not significant.

The following table shows the Member incentive units activity during 2014:

	Number of Units	Weighted Average Fair Value[(a)]	Total Fair Value ($ in millions)
Member Incentive Units:			
Unvested units at December 31, 2013	20,603	$ 1,067	$ 21.4
Units granted	—	$ —	$ —
Units vested	(7,586)	$ 3,935	$ 29.9
Units cancelled	(13,017)	$ 2,169	$ 28.2
Units at December 31, 2014	—	$ —	$ —

(a) Weighted average fair value shown is the grant date fair value for units granted, fair value at vesting for units vested, and fair value calculated at December 31, 2014 for units cancelled.

7. 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.

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, 2016 and 2015:

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	—	—	5,403	5,403
Total	$ —	$ 93,903	$ 5,403	$ 99,306

Description	Fair value measurements at December 31, 2015 using:			
	Level 1	Level 2	Level 3	Total
	($ in thousands)			
Derivative assets:				
Natural gas commodity derivatives	$ —	$ 4,674	$ —	$ 4,674
Total	$ —	$ 4,674	$ —	$ 4,674
Derivative liabilities:				
Natural gas commodity derivatives	$ —	$ 7,746	$ —	$ 7,746
Embedded derivative	—	—	16,025	16,025
Total	$ —	$ 7,746	$ 16,025	$ 23,771

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.

The Company determined that certain embedded features in the ARU 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 ARU Convertible Notes with all the features (including the change of control or Initial Public Offering (IPO) 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 ARU 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 as of December 31, 2016, are as follows:

Trading price of ARU Convertible Notes	80.0%
Probability of initial public offering or change in control	5% – 50% with a total of 100% over the expected term
Expected term	Between 1 and 3 years
Risk-free rate	1.15%
Discount rate with and without embedded features pre-exit	46.0%
Discount rate without embedded features post-exit	41.0%

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

	December 31, 2016	December 31, 2015
	($ in thousands)	
Balance, beginning of period	$ (16,025)	$ (269,168)
Change due to extinguishment of debt	7,006	41,550
Change in fair value included in earnings[(a)]	3,616	211,593
Balance, end of period	$ (5,403)	$ (16,025)

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

The carrying amount and estimated fair value of long-term debt as of December 31, 2016 and 2015 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, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	($ in thousands)			
ARU Second Lien Term Loans	$ 1,247,082	$ 1,293,490	$ 1,213,292	$ 752,718
ARU Junior Lien	—	—	526,103	313,245
ARU Convertible Notes	78,243	66,296	634,371	285,147
Total	$ 1,325,325	$ 1,359,786	$ 2,373,766	$ 1,351,110

8. Related Party Transactions

Management Services Agreement

The Company entered into a management services agreement with ARO (ARO MSA) effective August 1, 2015. Under the ARO MSA, ARO performs any and all general management, administrative and operating services requested by and at the direction of the Company. ARO 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. The ARO MSA will be 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, 2016 and 2015, the Company incurred $43.0 million and $26.7 million, respectively, for the services performed under the ARO MSA, of which $14.8 million and $3.1 million, respectively, related to direct labor or overhead and was recognized in natural gas, oil and NGL production expenses, exploration expenses or natural gas, oil and NGL properties, as applicable.

In 2013, the Company entered into the AEU MSA, with AEU Services, LLC (the Manager), a subsidiary of AELP, pursuant to which the Manager agreed to manage the Company's development and operations and provide substantially all of the Company's required operational and support services. Effective August 1, 2015, the MSA was terminated. For the years ended December 31, 2015 and 2014, the Company incurred costs of $40.8 million and $61.6 million, respectively, for services performed under the AEU MSA, of which $3.5 million and $5.3 million, respectively, related to direct labor or overhead and was recognized in natural gas, oil and NGL production expense or natural gas and oil properties, as applicable.

Incentive Units

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. See Note 6 for further information on the incentive compensation plan.

Sale of Mineral Rights

In December 2014, the Company sold its ownership of certain mineral rights and overriding royalty interests to a subsidiary of American Energy Minerals Holdings (AEMN). AEMN was under common control with the Company through EMG's controlling ownership. As the transaction was with an entity under common control, any difference between the proceeds received and the carrying amount of the net assets was recorded as an equity transaction. The Company received approximately $83.3 million as consideration, $2.0 million of which was recorded as a contribution to equity.

Note Payable to Member

In June 2015, the Company entered into a senior subordinated loan agreement with the Member, which allows the Member to make senior subordinated loans (Note Payable to Member) to the Company. The Company received $250.0 million in cash proceeds from the initial issuance of the Note Payable to Member during the second quarter of 2015 and $177.0 million in cash proceeds from the issuance of additional Note Payable to Member during the first quarter of 2016. The maturity date of the Note Payable to Member was the 91st day after the latest senior debt maturity date.

The Note Payable to Member bore interest at a rate of 17% which was paid in kind, compounded and added to the unpaid principal amount of the loan on a quarterly basis. During the years ended December 31, 2016 and 2015, the Company incurred $54.1 million and $24.7 million, respectively, of interest in kind.

The Note Payable to Member was to be converted into membership interests of the Company upon the earliest of the following, with defined terms similar to the ARU Convertible Notes: (a) the closing date of a Qualified PO, (b) the date on which all outstanding ARU Convertible Notes are converted into common stock of the Qualified PO Issuer, (c) satisfaction and discharge of the ARU Convertible Notes prior to the conversion of all outstanding ARU Convertible Notes into common stock or (d) entry by the Company into a first lien credit facility.

In September 2016, the Company's entry into the 2016 Credit Facility triggered the conversion of $505.7 million of the outstanding Note Payable to Member including all accrued and unpaid interest into equity.

Transactions Related to ARM

The Company has 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 ARM's natural gas production 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 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 natural gas, oil and NGL gathering, processing and transportation expense. For the year ended December 31, 2016, the Company recognized $37.0 million related to ARM's production as a reduction to natural gas, oil and NGL gathering, processing and transportation expense.

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. The costs incurred under the gas gathering agreement with Jefferson for the years ended December 31, 2016 and 2015 were $6.1 million and an immaterial amount, respectively. At December 31, 2016 and 2015, the Company had a payable to Jefferson of $1.8 million and an immaterial amount, respectively.

In September 2014, the Company entered into a gas gathering agreement with Ohio Gathering Company, LLC (Ohio Gathering), a subsidiary of MarkWest Utica EMG, LLC (MWU EMG), a joint venture between MarkWest Energy and EMG. Ohio Gathering is engaged in providing natural gas gathering services in the Utica Shale in eastern Ohio. The Company also entered into a gas processing and fractionation agreement with MWU EMG. EMG has significant influence over MWU EMG. The costs incurred for the years ended December 31, 2016, 2015 and 2014 under the gas gathering agreement with Ohio Gathering were $22.6 million, $11.8 million and $0.9 million, respectively. The costs incurred under the gas processing and fractionation agreement with MWU EMG for the years ended December 31, 2016, 2015 and 2014 were $24.8 million, $14.1 million and $1.3 million, respectively. At December 31, 2016 and 2015, the Company had a payable to MWU EMG of $8.0 million and $8.7 million, respectively.

In April 2014, the Company entered into a firm transportation agreement with Rockies Express Pipeline (REX). REX is a joint venture of Tallgrass Development, LP (through a subsidiary, Tallgrass Development owns a 50% interest in and operates the pipeline), Sempra US Gas & Power and Phillips 66. EMG has a 38% indirect interest in Tallgrass Development, LP. Transportation commitments commenced on August 1, 2015, and continue through 2035. The costs incurred under the firm transportation agreement with REX for the years ended December 31, 2016 and 2015 were $82.7 million and $34.2 million, respectively. There were no costs incurred during 2014. At December 31, 2016 and 2015, the Company had a payable to REX of $7.6 million and $7.0 million, respectively.

Furthermore, in October 2014, the Company entered into an additional firm transportation agreement with REX. Transportation commitments commenced in January 2017, and will continue through 2031. For information regarding the credit support requirements due to REX, see Note 9.

In August 2014, Traverse Midstream Partners, LLC (Traverse), which is controlled by EMG, entered into a joint venture agreement with Regency Energy Partners LP (Regency). On April 30, 2015, Regency merged with a wholly-owned subsidiary of Energy Transfer Partners, L.P. (ETP). ETP, through its subsidiaries, owns a 75% membership interest and Traverse, through its subsidiaries, owns a 25% membership interest in the joint venture, Ohio River System LLC (ORS). ORS operates a 52-mile natural gas gathering system. The system was placed in service in the fourth quarter of 2015. The Company has entered into a gathering and compression agreement with ORS to transport a portion of its gas produced from the Utica Shale in eastern Ohio. 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 year ended December 31, 2016 under the gathering and compression agreement with ORS were approximately $6.5 million. For information regarding the credit support requirements due to ORS, see Note 9. At December 31, 2016 and 2015, the Company had a payable to ORS of $1.5 million and an immaterial amount, respectively.

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. The first phase of the Rover Pipeline to Defiance, Ohio is projected to be completed in July 2017, with the second phase of the project to Dawn, Ontario projected to be completed in November 2017. 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. For information regarding the credit support requirements due to Rover, see Note 9.

ARU Convertible Notes

In December 2015, ARO purchased $10.5 million of the ARU Convertible Notes from a third party. As of December 31, 2016, the principal held by ARO, including interest paid in kind, was $10.9 million. Subsequent to December 31, 2016, ARO retired the outstanding principal and accrued and unpaid interest.

9. Commitments and Contingencies

Litigation Matters

Chesapeake Litigation. On February 17, 2015, Chesapeake Energy Corporation ("CHK") filed suit in the District Court of Oklahoma County, Oklahoma against the Company, 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, ARU and certain unnamed investors of the Company were dismissed from the lawsuit and are no longer parties to the suit.

Related to the Settlement Agreement, during the year ended December 31, 2016, we recognized a credit in litigation settlement expense of $4.1 million for the reduction in the accrual for contingent cash payments and paid $6.2 million, which settled all remaining liabilities associated with this litigation. For the year ended December 31, 2015, the Company recognized $93.0 million as litigation settlement expense related to the Settlement Agreement. The estimate consisted of $82.0 million for the assignment of the acreage and an $11.0 million accrual for contingent cash payments.

Additionally, the Settlement Agreement included a $10.0 million contingent cash payment to CHK upon the Company's completion of a successful equity raise from unaffiliated third parties within 180 days following the settlement date. On November 2, 2015, CHK filed suit in the District Court of Oklahoma County, Oklahoma against the Company and certain investors of the Company alleging that the Company breached the Settlement Agreement by not making the $10.0 million payment on or before October 6, 2015 and by failing to provide discovery cooperation. The Company believes the Settlement Agreement was clearly drafted and the contingency related to the $10.0 million contingent cash payment was not and is not owed to CHK. We intend to vigorously defend this claim and do not believe a negative outcome is probable; therefore, we have not recorded an accrual as of December 31, 2016.

Ohio Dormant Minerals Act (ODMA). The ODMA was enacted on March 22, 1989. This act stated that a mineral interest shall be deemed abandoned and vested in the owner of the surface if the mineral interest owner did not use its mineral rights during a 20 year period. In 2006, the ODMA was revised to clarify that a notification process had to be followed in order for the surface owner to assume the mineral rights. In 2016, the Ohio Supreme Court determined that the mineral owner retains the rights to their minerals as to the application of the 1989 ODMA unless the surface owner filed a quiet title action utilizing the 1989 ODMA prior to the 2006 revision. Following the 2006 revision, the surface owners could only gain the rights to the minerals if they followed the multi-step process outlined in the 2006 version of the ODMA. Shortly after the Ohio Supreme Court ruling, an appeal was filed with the Supreme Court of the United States. In January 2017, the Supreme Court denied hearing the appeal, thus upholding the Ohio Supreme Court's ruling as to the application of the ODMA.

Prior to the 2016 Ohio Supreme Court ruling, the Company acted in good faith by following then-current case law, which meant treating the 1989 ODMA as though it were self-executing. Despite this, the Company in the majority of instances involving producing and drilled units, acquired protective leases on both sides of the ODMA to ensure that its operations would not be impacted. In the limited instances in which the Company could not acquire protective leases it is now working with the mineral owners to secure new leases or lessees to secure assignments. The Company believes any loss exposure to potential claims will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

The Company is periodically involved in litigation and regulatory proceedings, investigations and disputes, including matters relating to commercial transactions, operations, landowner disputes 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 with the assistance of legal counsel and, if applicable, 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, we are 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 a 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, as of December 31, 2016:

Period	Pipeline Transportation	Drilling Rigs	Operating Lease Commitments	Total
		($ in thousands)		
2017	$ 356,167	$ 3,943	$ 623	$ 360,733
2018	576,250	—	645	576,895
2019	600,682	—	638	601,320
2020	603,105	—	—	603,105
2021	568,524	—	—	568,524
Thereafter	7,990,415	—	—	7,990,415
Total	$ 10,695,143	$ 3,943	$ 1,906	$ 10,700,992

Pipeline Transportation Commitments

As of December 31, 2016, the Company had certain 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. The Company made certain deposits to enter into these commitments, which are shown as deposits on pipeline transportation in the consolidated balance sheets.

As discussed in Note 8, the Company entered into firm transportation agreements with ORS and Rover. Pursuant to an agreement (the Pledge Agreement) between the Company and Traverse, Traverse is required to satisfy the Company's credit obligation to ORS (the ORS Pledge) and to Rover (the Rover Pledge). Upon the in-service date of ORS, the Company is obligated to provide credit support ranging from $40.0 million to $75.0 million. Under the Pledge Agreement, the Company has the option to post a first lien against Traverse's ownership in ORS in the event Traverse does not meet the requirements of the Pledge Agreement. Under the Rover Agreement, credit support in the amount of one year of demand charges, which may reach $245 million, is required.

Pursuant to the Pledge Agreement, the ORS Pledge and Rover Pledge are effective through April 30, 2021 unless the ARU Second Lien Term Loans and ARU Junior Lien are repaid, at which time the Company would be required to provide collateral directly to the counterparties. Additionally, prior to April 30, 2021, the Company is required to provide collateral directly to the counterparties if both (i) the Company has the availability under any credit facility and the financial wherewithal to do so and (ii) the board of managers of the Company approves of such collateral replacement (including the approval of any disinterested board members). Pursuant to the Pledge Agreement, the requirement to provide replacement collateral for the ORS Pledge and the Rover Pledge are to be made in the following order: first, the ORS Pledge must be replaced; second, the Rover Pledge must be replaced. In the event the Company is unable to completely replace the ORS Pledge or the Rover Pledge as set forth above, it will provide one or more letters of credit in favor of Traverse, to the maximum extent the Company has (i) the availability under any credit facility and the financial wherewithal to do so and (ii) the approval of the board of managers of the Company (including the approval of any disinterested board members).

Commencing February 1, 2016 for the ORS Pledge and July 1, 2016 for the Rover Pledge and until such time as the ORS Pledge and Rover Pledge are released, the Company will pay to 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 credit assurance obligations of the Company. As of December 31, 2016, the rates for the ORS and Rover Pledges were 3.0% and 2.75%, respectively. Assuming the value of the credit assurance obligation of the ORS Pledge is the minimum amount of $40 million, the Company expects to incur interest expense of $1.2 million in 2017 for the ORS Pledge. The Company expects to incur interest expense of $5.9 million during 2017, based on the one year credit support obligation for the Rover Pledge.

For the REX project, the Company was obligated to post $75.3 million of security for its shipping commitments when REX received its "7c" certificate from the Federal Energy Regulatory Commission (FERC). In the first quarter of 2015, REX received the 7c certificate and the Company posted the required security in the form of a surety bond. Upon divestiture of certain natural gas and oil properties during the second quarter of 2015, the Company's obligation was reduced to $61.6 million and the surety bond was reduced to $61.6 million. The Company is obligated to post an additional $67.8 million of collateral for its shipping commitments upon REX achieving certain milestones. The first milestone was achieved in the first quarter of 2015, and the Company posted its required $6.8 million of cash. In July 2015, the next milestone was reached and the Company posted another $10.2 million of cash. In February 2016, the next milestone was reached and the Company posted an additional $33.9 million of cash in March 2016. The project became fully operational in January 2017 and the Company posted a $16.9 million letter of credit as the final milestone was reached. See Note 8 for further discussion of these agreements.

Drilling Rig Commitments

As of December 31, 2016, the Company had three drilling rig contracts, all of which expire in 2017. Subsequent to December 31, 2016, the Company entered into three additional drilling rig contracts, all of which also expire in 2017. These contracts were entered into in the ordinary course of business to ensure rig availability allowing the Company to execute its business objectives.

Operating Lease Commitments

The Company leases certain vehicles and has future minimum rental commitments under these lease contracts in effect as of December 31, 2016.

Fixed Price Contract Commitments

The Company from time to time enters into agreements to sell certain volumes of our natural gas and oil production at fixed prices. These contracts can be for one month or longer and effectively insulate the Company from commodity price decreases below the contracted fixed price while they are in place.

The Company has entered into the following contracts:

	Natural Gas		Oil	
Period	Volumes (mmbtu/d)	Fixed Price $/mmbtu	Volumes (bbl/d)	Fixed Price $/bbl
January 2017	230,000	$ 3.06	1,500	$ 45.40
February 2017	150,000	$ 2.85	1,500	$ 45.40
March 2017	150,000	$ 2.85	1,500	$ 45.40
Q2 2017	50,000	$ 3.01	1,500	$ 45.40
Q3 2017	50,000	$ 3.01	—	—
Q4 2017	50,000	$ 3.01	—	—

Joint Venture Commitments

In 2013, the Company entered into a joint venture participation agreement with a third party 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 area of mutual interest 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. On February 19, 2016, the Company executed an amendment to extend the payment terms of carried costs from four years to five years. As of December 31, 2016 and 2015, the Company owed $103.3 million and $109.0 million, respectively, for this obligation. This obligation was discounted using an 11% discount rate, to reflect the imputation of interest, and is classified as an acquisition obligation in the consolidated balance sheets.

In 2014, the Company entered into a joint venture participation agreement with XTO Energy, Inc. (XTO) and Phillips Exploration, Inc. (Phillips). The participation agreement governs the funding, exploration, and development of the parties' jointly owned interests through the earliest to occur of either (a) January 29, 2024, (b) the point in time when all the lands covered by the leases have been made the subject of assignments, delivered to the respective receiving party or (c) the date at which the cumulative carry bank (Carry Bank), as defined in the agreement, equals zero dollars. The initial agreement provided that the Company would acquire a 40.0% interest in non-operated wells upon certain defined acreage and a 95% interest in operated wells upon certain defined acreage. In exchange, the Company would carry 100% of XTO and Phillips' share of development costs until the Carry Bank is depleted. The Carry Bank was defined in the initial agreement as the positive amount, if any, by which (a) the sum of 40% of the aggregate allocated value of the XTO core leases (as defined in the agreement), and 95% of the aggregate allocated value of the XTO non-core leases (as defined in the agreement) exceeds (b) the sum of 60% of the aggregate allocated value of the Company's core leases and the amount of all carried costs previously paid by the Company.

In March 2016, the Company and XTO amended the joint venture participation agreement such that the interest the Company would acquire would be reduced to a 5% interest in non-operated wells across a smaller amount of defined acreage and a 95% interest in operated wells across a larger amount of defined acreage, including an adjustment as to already earned acreage, which resulted in a reduction to the Carry Bank of approximately $80.0 million. The amendment revised certain contractual leasehold interests as defined in the agreement to provide XTO with a greater percentage interest in leases in a smaller XTO operated core area, with the Company obtaining an additional area to operate at a 95% working interest. As of December 31, 2016 and 2015, the Carry Bank was $79.7 million and $285.2 million, respectively. Participation in the joint venture is required by all parties while the Carry Bank has a positive balance. There are no required minimum payments associated with this agreement, as such the liability is not reflected in the contractual obligations table.

Supplemental Information on Natural Gas and Oil 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, Oil and NGL Property Acquisition, Exploration and Development

Costs incurred in natural gas, oil and NGL property acquisition, exploration and development activities are summarized as follows:

	Years Ended December 31,		
	2016	2015	2014
	($ in thousands)		
Acquisition costs of properties:			
Proved properties	$ 3,662	$ 1,837	$ 258,374
Unproved properties	497,144	281,955	1,663,693
Total property acquisition costs	500,806	283,792	1,922,067
Exploration costs	17,136	13,277	235,743
Development costs	265,280	722,693	135,683
Total	$ 783,222	$ 1,019,762	$ 2,293,493

Costs incurred in the table above include additions to asset retirement obligations of a nominal amount for each of the years ended December 31, 2016, 2015 and 2014, respectively.

Capitalized Costs Relating to Natural Gas and Oil Producing Activities

Capitalized costs related to the Company's natural gas and oil producing activities are summarized as follows:

	December 31,	
	2016	2015
	($ in thousands)	
Proved	$ 2,094,137	$ 1,641,276
Unproved	1,544,482	1,500,667
Total	3,638,619	3,141,943
Less accumulated depreciation, depletion and amortization	(368,663)	(139,633)
Net capitalized costs	$ 3,269,956	$ 3,002,310

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, 2016, 2015, and 2014 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). Proved reserve estimates for the year ended December 31, 2016 and 2015 were independently audited by Software Integrated Solutions (SIS) (formerly known as PetroTechnical Services), a Division of Schlumberger Technology Corporation. SIS audited approximately 100% of the Company's proved reserves at December 31, 2016 and 2015, respectively. 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 for the year ended December 31, 2014 were evaluated by SIS. SIS evaluated approximately 100% of the Company's proved reserves at December 31, 2014, noting the estimates of the Company's proved reserves, in aggregate, were reasonable.

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.

The following table sets forth proved reserves during the periods indicated for the Company:

	Natural Gas (mmcf)	Oil (mbbl)	NGL (mbbl)	Total (mmcfe)[(a)]
Proved Reserves at December 31, 2013	5,448	222	436	9,393
Extensions, discoveries and other additions	560,042	16,600	17,940	767,286
Revisions	(10,848)	114	(726)	(14,523)
Purchases of reserves	206,192	41	1,185	213,547
Sales of reserves	(10,242)	(16)	(39)	(10,568)
Production	(9,848)	(257)	(234)	(12,796)
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
Proved developed reserves:				
December 31, 2014	132,140	3,333	3,250	171,642
December 31, 2015	363,208	9,490	11,108	486,799
December 31, 2016	582,499	11,487	15,015	741,508
Proved undeveloped reserves:				
December 31, 2014	608,604	13,371	15,312	780,697
December 31, 2015	832,769	16,743	18,917	1,046,730
December 31, 2016	901,468	13,903	11,719	1,055,199

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

As of December 31, 2016, all of the Company's assets were located in the Utica Shale in Ohio.

During the year ended December 31, 2016, the Company added approximately 668,304 mmcfe 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 approximately 267,675 mmcfe relates to negative price revisions of 356,591 mmcfe, which more than offset the positive performance revisions of 88,916 mmcfe 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 approximately 783,544 mmcfe 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 153,579 mmcfe. 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.

During the year ended December 31, 2014, the Company added approximately 767,286 mmcfe in proved reserves through drilling activities and evaluation of proved areas in the Utica Shale. The majority of the downward revisions of approximately 14,523 mmcfe relate to performance revisions of the acquired properties.

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, oil and NGL 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, 2016, 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, 2016.

Results of Operations for Natural Gas and Oil Producing Activities

The following table sets forth the Company's results of operations for natural gas and oil producing activities for the following periods:

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Natural gas, oil and NGL sales	$ 367,149	$ 177,918	$ 58,141
Natural gas, oil and NGL production expense	(24,061)	(21,119)	(6,798)
Natural gas, oil and NGL gathering, processing and transportation expense	(186,300)	(86,973)	(19,738)
Production and ad valorem taxes	(7,623)	(2,504)	(389)
Exploration expenses	(269,982)	(85,394)	(22,984)
Acquisition expenses	—	(1,403)	(54,484)
Natural gas, oil and NGL depreciation, depletion and amortization	(229,038)	(133,410)	(21,185)
Results of operations	$ (349,855)	$ (152,885)	$ (67,437)

Standardized Measure of Discounted Future Net Cash Flows

The following summary sets forth the Company's standardized measure of future net cash flows from its proved natural gas, oil and NGL reserves:

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Future cash inflows	$ 5,157,113	$ 3,261,880	$ 4,348,628
Future production costs	(2,901,683)	(726,984)	(592,748)
Future development costs	(595,058)	(752,153)	(949,665)
Future net cash flows	1,660,372	1,782,743	2,806,215
Discount to present value at 10% annual rate	(804,018)	(881,423)	(1,500,990)
Standardized measure of discounted future net cash flows	$ 856,354	$ 901,320	$ 1,305,225

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in the Company's standardized measure of future net cash flows relating from its proved natural gas, oil and NGL reserves.

	Years Ended December 31,		
	2016	2015	2014
		($ in thousands)	
Standardized measure of discounted future net cash flows at beginning of period	$ 901,320	$ 1,305,225	$ 28,550
Sales of natural gas and oil produced, net of production costs	(149,166)	(67,322)	(31,216)
Net changes in prices and production costs	(318,823)	(945,554)	(31,027)
Extensions and discoveries, net of production and development costs	274,008	455,498	1,059,844
Changes in future development costs	165,369	28,387	2,757
Development costs incurred during the period that reduced future development costs	124,389	209,563	4,158
Revisions of previous quantity estimates	(171,887)	(69,690)	(26,208)
Purchase of reserves	—	—	257,264
Sales of reserves	—	(84,001)	(18,518)
Accretion of discount	90,132	130,522	2,855
Changes in production rates and other	(58,988)	(61,308)	56,766
Standardized measure of discounted future net cash flows at end of period	$ 856,354	$ 901,320	$ 1,305,225