CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) AND MANAGEMENT'S DISCUSSION AND ANALYSIS

Ascent Resources Utica Holdings, LLC

As of March 31, 2019 and December 31, 2018 and for the Three Months Ended March 31, 2019 and 2018.

ASCENT RESOURCES UTICA HOLDINGS, LLC
INDEX TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

($ in thousands)	March 31, 2019	December 31, 2018
Current Assets:		
Cash and cash equivalents	$ 10,445	$ 11,030
Accounts receivable – natural gas, oil and NGL sales	265,917	401,814
Accounts receivable – joint interest and other	46,011	50,531
Short-term derivative assets	15,609	52,404
Other current assets	8,194	6,135
Total Current Assets	346,176	521,914
Property and Equipment:		
Natural gas and oil properties, based on successful efforts accounting	7,354,947	7,066,947
Other property and equipment	28,167	27,454
Less: accumulated depreciation, depletion and amortization	(1,345,633)	(1,185,772)
Property and Equipment, net	6,037,481	5,908,629
Other Assets:		
Long-term derivative assets	18,648	39,543
Other long-term assets	15,354	16,736
Total Assets	$ 6,417,659	$ 6,486,822
Current Liabilities:		
Accounts payable	$ 94,040	$ 106,839
Revenue payable	146,384	178,111
Accrued interest	78,105	41,510
Short-term derivative liabilities	52,507	1,068
Other current liabilities	304,902	328,580
Total Current Liabilities	675,938	656,108
Long-Term Liabilities:		
Long-term debt, net	2,563,905	2,582,820
Long-term derivative liabilities	39,383	21,441
Other long-term liabilities	8,469	11,356
Total Long-Term Liabilities	2,611,757	2,615,617
Commitments and contingencies (Note 9)		
Member's Equity	3,129,964	3,215,097
Total Liabilities and Member's Equity	$ 6,417,659	$ 6,486,822

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

($ in thousands)	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Revenues:		
Natural gas	$ 460,378	$ 252,846
Oil	37,543	18,730
NGL	35,442	16,874
Commodity derivative (loss) gain	(157,189)	217
Total Revenues	376,174	288,667
Operating Expenses:		
Lease operating expenses	17,919	13,130
Gathering, processing and transportation expenses	200,095	135,971
Production and ad valorem taxes	8,472	3,801
Exploration expenses	39,254	44,726
General and administrative expenses	16,344	10,267
Natural gas and oil depreciation, depletion and amortization	159,132	95,825
Depreciation and amortization of other assets	765	932
Total Operating Expenses	441,981	304,652
Loss from Operations	(65,807)	(15,985)
Other (Expense) Income:		
Interest expense, net	(21,143)	(19,577)
Change in fair value of embedded derivative	1,138	(336)
Other income (loss)	503	(149)
Total Other Expense	(19,502)	(20,062)
Net Loss	$ (85,309)	$ (36,047)

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
(Unaudited)

($ in thousands)	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Balance, Beginning of Period	$ 3,215,097	$ 2,182,500
Contributions from Member	176	4,693
Net loss	(85,309)	(36,047)
Balance, End of Period	$ 3,129,964	$ 2,151,146

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

($ in thousands)	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Cash Flows from Operating Activities:		
Net loss	$ (85,309)	$ (36,047)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	159,897	96,757
Change in fair value of commodity derivatives	127,071	10,115
Impairment of unproved natural gas and oil properties	38,689	44,106
Change in fair value of embedded derivative	(1,138)	336
Other	(6)	(1,679)
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable and other assets	128,091	(15,149)
(Decrease) increase in accounts payable, liabilities and other	(25,556)	62,528
Net Cash Provided by Operating Activities	341,739	160,967
Cash Flows from Investing Activities:		
Drilling and completion costs	(268,518)	(190,199)
Acquisitions of natural gas and oil properties	(50,050)	(34,003)
Proceeds from divestitures of natural gas and oil properties	—	6,564
Additions to other property and equipment	(694)	(67)
Net Cash Used in Investing Activities	(319,262)	(217,705)
Cash Flows from Financing Activities:		
Proceeds from credit facility borrowings	325,000	35,000
Repayment of credit facility borrowings	(348,000)	—
Cash paid for debt issuance costs	(62)	(1,291)
Net Cash (Used in) Provided by Financing Activities	(23,062)	33,709
Net Decrease in Cash and Cash Equivalents	(585)	(23,029)
Cash and Cash Equivalents, Beginning of Period	11,030	119,215
Cash and Cash Equivalents, End of Period	$ 10,445	$ 96,186
Supplemental disclosures of cash flow information:		
Interest paid, net of capitalized interest and interest paid in kind	$ 2,371	$ 6,593
Supplemental disclosures of significant non-cash investing and financing activities:		
(Decrease) increase in accrued capital expenditures	$ (9,813)	$ 30,183
Contributions from Member	$ 176	$ 4,693

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation and Consolidation

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

The accompanying unaudited condensed consolidated financial statements and notes of the Company were prepared in accordance with United States generally accepted accounting principles (US GAAP), and intercompany accounts and balances have been eliminated. ARUH is a wholly-owned subsidiary of Ascent Resources Operating, LLC (the Member), which is an indirect, wholly-owned subsidiary of Ascent Resources, LLC (the Parent). The Parent is majority owned by investment funds controlled by The Energy & Minerals Group (EMG) and First Reserve Corporation (First Reserve). Certain disclosures normally included in consolidated financial statements prepared in accordance with US GAAP have been omitted. The unaudited condensed consolidated financial statements and notes should be read in conjunction with the Company's audited consolidated financial statements and notes for the year ended December 31, 2018.

The unaudited condensed consolidated financial statements furnished in this report reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods. All such adjustments are of a normal recurring nature. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Use of Estimates

The preparation of condensed 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 condensed consolidated financial statements. Actual amounts could differ from these estimates. Estimates of natural gas, oil and NGL reserves and their values, future production rates and future costs and expenses are the most significant of the Company's estimates.

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

Customer Credit Risk

The Company is subject to credit risk resulting from the concentration of its natural gas, oil and NGL receivables. If the Company's largest customers stopped purchasing its natural gas, oil or NGL, the Company's revenues could decline and its operating results and financial condition could be harmed; however, management does not believe the loss of any single purchaser would materially impact the Company's operating results, as natural gas, oil and NGL are fungible products with well-established markets and the Company transacts with numerous purchasers in its operating region.

The Company also has joint interest receivables, which arise from billings to entities that own working interests in the wells the Company operates. These entities participate in the Company's wells primarily based on their ownership in leases on which the Company intends to drill. The Company has little ability to control whether these entities will participate in its wells but can require these entities to prepay drilling costs. The Company historically has not incurred losses on its joint interest receivables.

Reclassifications

Certain reclassifications have been made to the Company's March 31, 2018 condensed consolidated financial statements to conform to the presentation used for the March 31, 2019 condensed consolidated financial statements.

Revision

Management of the Company determined that incentive units issued by affiliates of the Company did not meet the requirements for liability classification under ASC 718, *Compensation - Stock Compensation* (ASC 718) and met either the requirements for equity classification under ASC 718 or treatment under ASC 710, *Compensation*, as disclosed in the Company's restated condensed consolidated financial statements as of September 30, 2018 and for the three and nine months ended September 30, 2018. The principal effect of this change in accounting is that general and administrative expenses were overstated and Member's equity was understated. As a result, the Company has revised the condensed consolidated statement of operations for the three months ended March 31, 2018 to decrease general and administrative expenses by $6.3 million and has also revised the condensed consolidated statement of Member's equity for the same period to increase contributions from Member by $1.2 million. The revision had no impact on the previously reported net cash provided by (used in) operating, investing or financing activities.

Adopted and Recently Issued Accounting Pronouncements

In August 2018, the FASB issued ASU 2018-13, *Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement (Topic 820)*. The amendments in this ASU remove, modify and add to the disclosure requirements for fair value measurements. The new standard clarifies that entities should disclose information about the uncertainty of fair value measurements as of the reporting date. These amendments are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019 for both public and non-public entities. The amended guidance on changes in unrealized gains and losses, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements and the narrative description of measurement uncertainty should be applied prospectively for only the most recent interim or annual period presented in the initial fiscal year of adoption. All other amendments should be applied retrospectively to all periods presented upon their effective date. Entities are permitted to early adopt any removed or modified disclosures and delay the adoption of the additional disclosures until their effective date. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*. The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the lease commencement date: (1) a lease liability, which is a lessee’s obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. Classification of leases as either a finance or operating lease will determine the recognition, measurement and presentation of expenses. This accounting standards update also requires certain quantitative and qualitative disclosures about leasing arrangements. Lessees and lessors can apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented on the financial statements. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842), Land Easement Practical Expedient for Transition to Topic 842*. This ASU would permit an entity to not apply Topic 842 to land easements and rights-of-way that existed or expired before the effective date of Topic 842 and that were not previously assessed under Topic 840. An entity would continue to apply its current accounting policy for land easements that existed before the effective date of Topic 842. Once an entity adopts Topic 842, it would be applied prospectively to all new (or modified) land easements and rights-of-way to determine whether the arrangement should be accounted for as a lease. In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842), Targeted Improvements*. This ASU would permit an entity to apply a transition method at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption instead of recasting prior year results. In March 2019, the FASB issued ASU 2019-01, *Leases (Topic 842), Codification Improvements*. The intent of this ASU is to clarify the guidance more generally and to correct unintended application of the guidance by, among other issues, explicitly providing an exception to the interim period disclosures required for changes in accounting principles during the period in which an entity adopts Topic 842. The amendments are effective for interim and annual reporting periods beginning after December 15, 2018 for public business entities and for periods beginning after December 15, 2019 for non-public entities, with early adoption permitted. The Company is in the process of evaluating the impact of this ASU on its consolidated financial statements and related disclosures. Based on the Company’s preliminary review, the Company expects to have leases with durations greater than twelve months on its balance sheet along with expanded lease disclosures and internal control changes necessary for adoption.

Subsequent Events

The Company evaluated its March 31, 2019 condensed consolidated financial statements for subsequent events through May 15, 2019, the date the condensed consolidated financial statements were available to be issued, and such events are noted within.

2. Revenue from Contracts with Customers

The Company’s revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGL that are extracted from the Company’s natural gas. Sales of natural gas, oil and NGL are recognized when production is sold to a customer at a fixed or determinable price, delivery has occurred, control has transferred and collection of the revenue is probable. The Company generally considers the delivery of each unit (mmbtu, bbl or gallon) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to (i) whether the purchaser can direct the use of the product, (ii) the transfer of significant risks, (iii) the Company’s right to payment and (iv) transfer of legal title.

Revenue is measured based on consideration specified in the contract with the customer and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The Company records revenue in the month production is delivered to the customer. However, settlement statements for certain natural gas and NGL sales may be received for 30 to 90 days after the date production is delivered.

Under the Company's natural gas sales contracts, it delivers natural gas to the customer at an agreed upon delivery point. Natural gas is transported from the wellhead to delivery points specified under sales contracts. To deliver natural gas to these points, third parties gather, compress, process and transport the Company's natural gas. The Company's sales contracts provide that the Company generally receives a specific index price adjusted for pricing differentials. The Company transfers control of the product to the customer at the delivery point and recognizes revenue based on the contract price. The costs incurred to gather, compress, process and transport the natural gas prior to the point when control is transferred to the customer are recorded on the condensed consolidated statements of operations as gathering, processing and transportation expenses.

NGL, which are extracted from natural gas through processing, are either sold by the Company directly or to the processor under processing contracts. For NGL sold by the Company directly, the sales contracts provide that the product is delivered to the customer at an agreed upon delivery point and that the Company generally receives a specific index price adjusted for pricing differentials. The Company transfers control of the product to the customer at the delivery point and recognizes revenue based on the contract price. The costs to process and transport NGL to the delivery points are recorded on the condensed consolidated statements of operations as gathering, processing and transportation expenses. For NGL sold to the processor, control is transferred by the Company to the processor at the tailgate of the processing plant, and revenue is recognized based on the price received from the processor.

Under the Company's oil sales contracts, oil is sold to the customer from storage tanks near the wellhead, and the Company collects a contractually agreed upon index price, net of pricing differentials. The Company transfers control of the product from the storage tanks to the customer and recognizes revenue based on the contract price.

The recognition of gains or losses on derivative instruments is not considered revenue from contracts with customers subject to ASC 606, *Revenue from Contracts with Customers* (ASC 606).

The Company has elected to exclude from the measurement of the transaction price all taxes assessed by governmental authorities that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Company from a customer.

Disaggregation of Revenue

The Company's revenues are comprised solely of revenues from customers and include the sale of natural gas, oil and NGL, which are each presented separately on the Company's condensed consolidated statements of operations. The Company believes that the disaggregation of revenue into these three major product types appropriately depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors based on the Company's single geographic location.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient option in ASC 606 which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's sales contracts, each unit of production delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Certain of the Company's product sales are short-term in nature, generally through evergreen contracts with terms of one year or less. These contracts typically automatically renew under the same provisions. For these contracts, the Company has utilized the practical expedient option in ASC 606 which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Contract Balances

Under the Company's sales contracts, customers are invoiced after the Company's performance obligations have been satisfied, generally when control of the product has been transferred to the customer, at which point payment is unconditional. Accordingly, the Company's contracts do not give rise to contract assets or liabilities under ASC 606. At March 31, 2019 and December 31, 2018, receivables from contracts with customers were $265.9 million and $401.8 million, respectively, and were reported in accounts receivable – natural gas, oil and NGL sales on the condensed consolidated balance sheets.

3. Acquisitions

2018 Acquisitions

During the third quarter of 2018, the Company acquired approximately 113,600 net leasehold acres and royalty interests on approximately 69,600 acres of fee minerals upon the closing of the CNX and Hess Acquisition, the Salt Fork Acquisition and the UMD Acquisition, all of which are defined and discussed below.

CNX and Hess Acquisition. On August 30, 2018, the Company acquired producing and non-producing natural gas and oil properties in the Utica Shale, which included approximately 24,000 net leasehold acres, 46,000 acres of unencumbered fee minerals and royalties on 8,400 acres of fee minerals, from CNX Resources Corporation and Hess Corporation (together, the CNX and Hess Acquisition) for consideration of approximately $766.1 million, subject to post-closing adjustments. Funding for the CNX and Hess Acquisition consisted of borrowings under the Credit Facility and cash proceeds contributed to the Company from a common equity offering by the Parent.

The CNX and Hess Acquisition qualified as a business combination, and as such, the Company estimated the fair value of these properties as of the acquisition date in accordance with FASB ASC 805, *Business Combinations* (ASC 805). The fair value of the assets acquired and liabilities assumed was estimated using assumptions that represent Level 3 inputs. See Note 7, *Fair Value Measurement on a Non-recurring Basis,* for additional discussion of the fair value estimates. No goodwill or bargain purchase gain was recognized in conjunction with the acquisition. The following table presents the fair value of the assets acquired and liabilities assumed in the CNX and Hess Acquisition as of the acquisition date:

($ in thousands)		Assets Acquired/ (Liabilities Assumed)
Consideration:		
Cash, net of purchase price adjustments	$	766,141
Assets acquired:		
Proved natural gas and oil properties	$	403,726
Unproved natural gas and oil properties		365,891
Accounts receivable – joint interest and other		2,408
Liabilities assumed:		
Revenue payable		(5,002)
Other current liabilities		(542)
Asset retirement obligations		(340)
Fair Value of Net Assets Acquired	$	766,141

Salt Fork Acquisition. In August 2018, the Company acquired primarily non-producing natural gas and oil properties in the Utica Shale, which consisted of approximately 23,000 net unproved leasehold acres and approximately 1,000 acres of unencumbered fee minerals, from Salt Fork Resources Employer, LLC (Salt Fork) for $223.0 million (the Salt Fork Acquisition), subject to customary closing adjustments. The Salt Fork Acquisition was funded entirely with common equity issued directly to the seller from the Parent.

UMD Acquisition. On July 13, 2018, the Company acquired producing and non-producing natural gas and oil properties and associated derivative assets in the Utica Shale, which included approximately 5,400 net leasehold acres and 14,200 acres of unencumbered fee minerals, from Utica Minerals Development, LLC (UMD) for consideration of approximately $501.7 million (the UMD Acquisition), including customary closing adjustments and approximately $238.6 million of common equity issued directly from the Parent. The cash consideration was funded using proceeds contributed to the Company from a common equity offering by the Parent.

The UMD Acquisition qualified as a business combination, and as such, the Company estimated the fair value of these properties as of the acquisition date in accordance with ASC 805. The fair value of the assets acquired and liabilities assumed was estimated using assumptions that represent Level 3 inputs. See Note 7, *Fair Value Measurement on a Non-recurring Basis,* for additional discussion of the fair value estimates. No goodwill or bargain purchase gain was recognized in conjunction with the purchase. The following table presents the fair value of the assets acquired and liabilities assumed in the UMD Acquisition as of the acquisition date:

($ in thousands)	Assets Acquired/ (Liabilities Assumed)
Consideration:	
Cash, net of purchase price adjustments	$ 263,151
Equity issued directly from Parent	238,560
Total Consideration	$ 501,711
Assets acquired:	
Proved natural gas and oil properties	$ 270,580
Unproved natural gas and oil properties	222,311
Commodity derivative assets	8,826
Liabilities assumed:	
Asset retirement obligations	(6)
Fair Value of Net Assets Acquired	$ 501,711

Pro Forma Information (Unaudited). The following unaudited pro forma combined financial information presents the Company's results as though the CNX and Hess Acquisition and the UMD Acquisition had both been completed on January 1, 2017. The pro forma combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the CNX and Hess Acquisition and UMD Acquisition taken place on January 1, 2017; furthermore, the financial information is not intended to be a projection of future results.

($ in thousands)	Three Months Ended March 31, 2018
Pro forma revenues	$ 347,580
Pro forma net loss	$ (3,849)

4. Property and Equipment

Net property and equipment included the following:

($ in thousands)	March 31, 2019	December 31, 2018
Proved natural gas and oil properties	$ 5,893,446	$ 5,457,911
Unproved natural gas and oil properties	1,461,501	1,609,036
Other property and equipment	28,167	27,454
Total Property and Equipment	7,383,114	7,094,401
Accumulated depreciation, depletion and amortization	(1,345,633)	(1,185,772)
Property and Equipment, net	$ 6,037,481	$ 5,908,629

5. Long-Term Debt

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

($ in thousands)	March 31, 2019	December 31, 2018
Senior notes due 2022[(a)]	$ 975,000	$ 975,000
Senior notes due 2026[(b)]	600,000	600,000
Credit Facility[(c)]	925,000	948,000
Convertible notes due 2021[(d)]	75,308	74,116
Embedded derivative	3,888	5,026
Net unamortized debt issuance costs	(4,091)	(4,243)
Net unamortized debt discounts	(11,200)	(15,079)
Total Long-Term Debt, net	$ 2,563,905	$ 2,582,820

(a) The interest rate was 10.00% as of March 31, 2019 and December 31, 2018.
(b) The interest rate was 7.00% as of March 31, 2019 and December 31, 2018.
(c) The interest rate was 4.50% and 4.36% as of March 31, 2019 and December 31, 2018, respectively.
(d) The interest rate was 6.50% as of March 31, 2019 and December 31, 2018.

Senior Notes

In April 2017, the Company issued $1.5 billion in aggregate principal amount of senior unsecured notes (2022 Notes) in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The 2022 Notes are due on April 1, 2022, and interest is payable at an annual rate of 10.00% on April 1 and October 1 of each year, which commenced on October 1, 2017. Net proceeds to the Company from the issuance of the 2022 Notes were approximately $1.47 billion. The proceeds were used to repay and retire all of the Company's outstanding second lien term loans and for general corporate purposes. The Company's obligations under the 2022 Notes are fully and unconditionally guaranteed, jointly and severally, by any current and future material subsidiaries of the Company. The 2022 Notes are governed by an indenture containing covenants limiting, among other things, the Company's ability to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into certain transactions with affiliates. The Company was in compliance with all applicable covenants under the indenture as of March 31, 2019.

In October 2018, the Company issued $600.0 million in aggregate principal amount of senior unsecured notes (2026 Notes) in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The 2026 Notes are due on November 1, 2026, and interest is payable at an annual rate of 7.00% on May 1 and November 1 of each year, beginning with May 1, 2019. The Company used approximately $577.5 million of the $587.2 million net proceeds to exercise its right to redeem 35%, or $525.0 million, of the aggregate principal amount of the 2022 Notes (the Redemption) at a redemption price equal to 110% of the principal thereof. The Company also paid $1.5 million of accrued and unpaid interest up to, but excluding, the date of the Redemption and used the remaining net proceeds to repay borrowings under the Credit Facility. The Company's obligations under the 2026 Notes are fully and unconditionally guaranteed, jointly and severally, by any current and future material subsidiaries of the Company. The 2026 Notes are governed by an indenture containing covenants limiting, among other things, the Company's ability to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into certain transactions with affiliates. The Company was in compliance with all applicable covenants under the indenture as of March 31, 2019.

At any time prior to November 1, 2021, the Company may redeem up to 40% of the aggregate principal amount of the 2026 Notes at a price equal to 107% of the principal amount, plus accrued and unpaid interest up to, but excluding, the redemption date, with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Additionally, at any time prior to April 1, 2020 for the 2022 Notes or November 1, 2021 for the 2026 Notes (together, the Senior Notes), the Company may redeem some or all of the Senior Notes, respectively, subject to a make-whole premium plus accrued and unpaid interest up to, but excluding, the redemption date. The Company may redeem some or all of the Senior Notes at the applicable redemption prices (expressed as percentages of principal amount) set forth in the table below on the dates set forth therein:

Senior Notes	Redemption on or after	Redemption Price
2022 Notes	April 1, 2020	107.500%
2022 Notes	April 1, 2021	105.000%
2022 Notes	October 1, 2021 and thereafter	100.000%
2026 Notes	November 1, 2021	103.500%
2026 Notes	November 1, 2022	102.333%
2026 Notes	November 1, 2023	101.167%
2026 Notes	November 1, 2024 and thereafter	100.000%

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

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

In connection with the issuance and sale of the 2022 Notes, the Company entered into a registration rights agreement with the initial purchasers. Pursuant to the registration rights agreement, the Company has agreed to file a registration statement with the United States Securities and Exchange Commission subsequent to an initial public offering of the Company so that the holders may exchange the 2022 Notes for registered notes that have substantially identical terms. In addition, the Company has agreed to exchange the guarantee related to the 2022 Notes for a registered guarantee having substantially the same terms. The Company will use commercially reasonable efforts to cause the exchange to be completed within 365 days following the closing date of an underwritten public offering by ARUH or any parent entity. If the Company fails to comply with certain obligations to register the 2022 Notes, then for the first 90-day period immediately following such failure the interest rate on the 2022 Notes will increase by 0.25% per annum. The interest rate on the 2022 Notes will increase by an additional 0.25% per annum with respect to each subsequent 90-day period the Company fails to comply with its obligations under the registration rights agreement, up to a maximum aggregate increase of 1.00% per annum. Upon regaining compliance with the terms of the registration rights agreement, the increase in interest rate on the 2022 Notes will cease, and the interest rate will return to the stated annual rate of 10.00%.

Credit Facility

In 2017 and 2018, the Company amended the April 2017 credit agreement for its senior secured revolving credit facility (Credit Facility). The amended $2.5 billion Credit Facility matures on December 31, 2021, and as of March 31, 2019, it had a fully committed borrowing base of $2.0 billion, of which $500.0 million was authorized for letters of credit. The Credit Facility is secured by liens on substantially all of the Company's assets, including its natural gas and oil properties, and the amount available to be borrowed under the Credit Facility is subject to a borrowing base that is required to be redetermined semiannually on or about April 1 and October 1 of each year based on the estimated value and future net cash flows of the Company's proved natural gas, oil and NGL reserves and the value of its commodity hedge positions. Additionally, the Company may request an interim redetermination of the borrowing base in certain circumstances, including acquisitions of proved reserves in excess of certain thresholds. As of March 31, 2019, the Company had borrowings of $925.0 million and $323.1 million of letters of credit outstanding under the Credit Facility. In April 2019, the Credit Facility agreement was further amended, which most notably affirmed the borrowing base at $2.0 billion, reduced the Company's fees on letters of credit and reduced the amount authorized for letters of credit to $400.0 million.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the prime rate announced by the administrative agent, (ii) the Federal Reserve Bank of New York federal funds rate plus 0.50% or (iii) the rate for 1-month Eurodollar loans, plus an applicable margin ranging from 0.50% to 1.50% per annum. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 1.50% to 2.50% per annum. Due to the weighted average 1-month LIBOR being 2.50% for the applicable interest periods on the most recent election dates, the Company was subject to a weighted average rate of 4.50% per annum as of March 31, 2019. The Company may repay any amounts borrowed prior to the maturity date without any premium or penalty.

Under the Credit Facility agreement, the Company is subject to commitment fees payable to the administrative agent for the unutilized available borrowing base. As of March 31, 2019, such fees were incurred at a rate of 0.50% per annum; however, in April 2019 the rate was amended to range from 0.375% to 0.50% based on Credit Facility utilization. Additionally, the Company is subject to letter of credit participation fees payable to the administrative agent which escalate based on applicable margins, ranging from 1.50% to 2.50% per annum, in accordance with the balance of outstanding letters of credit issued. The Company is also subject to a letter of credit fronting fee that is payable to the issuing bank at a rate of 0.125% per annum of the balance of outstanding letters of credit issued. During the three months ended March 31, 2019 and 2018, the Company incurred $4.8 million and $5.7 million, respectively, in commitment, participation and fronting fees on letters of credit outstanding and $11.4 million and a nominal amount, respectively, in interest on principal borrowings under the Credit Facility, which are presented as interest expense on the condensed consolidated statements of operations.

The Credit Facility contains restrictive covenants including, but not limited to, restrictions on the Company's ability to incur additional indebtedness, create certain liens on assets, make certain investments or restricted payments, make loans to others, make certain payments, consolidate or merge, hedge hydrocarbons, enter into transactions with affiliates, dispose of assets or engage in certain other transactions without the prior consent of the lenders. The Credit Facility also requires the Company to maintain the following two financial ratios: 1) a consolidated leverage ratio, which requires the Company to maintain a consolidated funded indebtedness to consolidated EBITDAX (as defined in the agreement) ratio of not more than 4.00 to 1.00 for each fiscal quarter and 2) a modified current ratio per the covenants, which requires the Company to maintain consolidated current assets to consolidated current liabilities of not less than 1.00 to 1.00 as of the end of each fiscal quarter. As of March 31, 2019, the Company was in compliance with the financial covenants of the Credit Facility.

As of March 31, 2019, the Company had $15.1 million in unamortized debt issuance costs associated with the Credit Facility, which are presented as other long-term assets on the condensed consolidated balance sheet.

Convertible Notes

In 2014, the Company issued $1.0 billion of convertible notes due 2021 (Convertible Notes). Through multiple transactions from 2015 through 2017, the Company repurchased or otherwise retired $950.3 million in aggregate principal and accrued and unpaid interest of the Convertible Notes, including $11.1 million of outstanding principal and accrued and unpaid interest in March 2017 contributed to the Company by the Member.

As of March 31, 2019, the Company had $75.3 million in aggregate principal, including accrued and unpaid interest, outstanding of the Convertible Notes. The Convertible Notes mature on March 1, 2021 and are subordinate to the Senior Notes, which rank senior in right of payment. Interest may be paid in cash or in kind semi-annually in arrears on March 1 and September 1 of each year and is currently payable at an annual rate of 6.50%. The Company has elected to pay interest in kind on each interest payment date since September 2015. Upon maturity, unless earlier repurchased or converted, the Company will be required to redeem the Convertible Notes at 153.8% of the outstanding principal value, plus accrued and unpaid interest up to, but not including, the maturity date. The Company accretes the 53.8% premium to interest expense through the maturity date using the effective interest method.

Conversion of the Convertible Notes into common shares of the qualified public offering issuer (Qualified PO Issuer) following a qualified initial public offering (Qualified PO) is at the option of the noteholders. 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. Following the closing of a Qualified PO, the Company will have the option to redeem all of the Convertible Notes that were not otherwise converted at a price equal to 100% of the principal of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any. The Convertible Notes also provide for cash redemption upon a change of control event at the option of the holders at a price, including a premium, of 153.8% of the principal amount of the Convertible Notes, plus accrued and unpaid interest up to, but not including, the date of redemption. The Convertible Notes are not redeemable by the holders prior to a change of control or the closing of a Qualified PO.

Certain embedded features in the Convertible Notes are required to be bifurcated and accounted for as a derivative. The fair value of the embedded derivative was $3.9 million and $5.0 million as of March 31, 2019 and December 31, 2018, respectively.

Interest Expense

Interest expense was comprised of the following:

($ in thousands)	Three Months Ended March 31, 2019	2018
Interest expense	$ 53,063	$ 45,075
Long-term debt accretion expense	3,879	3,543
Deferred debt issuance cost amortization	1,556	1,058
Capitalized interest	(37,355)	(30,099)
Total Interest Expense, net	$ 21,143	$ 19,577

6. Commodity Derivative Instruments

The Company uses commodity derivative instruments to reduce its exposure to fluctuations in future commodity prices and to protect its anticipated operating cash flow against significant market movements or volatility. The Company does not use commodity derivative instruments for speculative or trading purposes. As of March 31, 2019, the Company's natural gas, oil and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*. The Company receives a fixed price for its natural gas, oil or NGL production and pays a variable market price to the counterparty.

- *Call Options*. The Company sells call options in exchange for a premium, which establish the maximum price the Company will receive for contracted commodity volumes. At the time of settlement, if the market price exceeds the fixed price of the call option, the Company pays the difference to the counterparty. From time to time, the Company may sell future call options to obtain more favorable strike prices on swap or collar contracts.

- *Collars*. These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price, the Company pays the difference between market price and the strike price of the sold call to the counterparty. If the market price falls below the put strike price, the Company receives the difference between the market price and the strike price of the purchased put from the counterparty. If the market price is between the put and the call strike prices, no payments are due to or from either party.

- *Three-Way Collars*. Three-way collars consist of a traditional collar and the sale by the Company of an additional put option in exchange for more favorable strike prices on purchased put or sold call options.

- *Basis Swaps*. Given that the Company's natural gas production is sold at various delivery points that at times may have material spreads or volatility relative to NYMEX, basis swaps are periodically used at the following basis points to fix the differential between product prices at one market location versus another: Chicago (Citygate), Dawn (Ontario), MichCon, Rex Zone 3, Dominion South, TCO and Tetco M-2. Under these instruments, the Company receives the fixed price differential and pays the floating market price differential to the counterparty for the contracted volumes.

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

The following table sets forth the average volumes per day associated with the Company's outstanding natural gas derivative instruments as of March 31, 2019, the contracted weighted average natural gas prices and the estimated fair values:

		Weighted Average Prices ($/mmbtu)				
	Average Volume (mmbtu/d)	Fixed Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Natural gas:						
Swaps:						$ 28,810
Remaining in 2019	1,686,000	$ 2.85				
2020	1,430,000	$ 2.74				
2021	410,000	$ 2.73				
2022	50,000	$ 2.82				
Collars:						2,059
Remaining in 2019	8,000		$ 3.40	$ 2.75		
2020	140,000		$ 3.09	$ 2.59		
2021	10,000		$ 2.91	$ 2.50		
Three-way collars:						(3,574)
2021	270,000		$ 2.91	$ 2.50	$ 2.00	
2022	160,000		$ 3.00	$ 2.50	$ 2.01	
Call options:						(61,168)
Remaining in 2019	94,000		$ 3.00			
2020	250,000		$ 3.00			
2021	335,000		$ 3.02			
2022	260,000		$ 3.04			
2023	170,000		$ 3.00			
Basis swaps:						(22,900)
Remaining in 2019	669,000	$ (0.29)				
2020	706,000	$ (0.37)				
2021	30,000	$ (0.52)				
Total Estimated Fair Value						$ (56,773)

The following table sets forth the average volumes per day associated with the Company's outstanding oil derivative instruments as of March 31, 2019, the contracted weighted average oil prices and the estimated fair values:

		Weighted Average Prices ($/bbl)		
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
Oil:				
Swaps:				$ (9,084)
Remaining in 2019	7,000	$ 56.56		
2020	7,500	$ 57.20		
2021	1,000	$ 60.06		
Call options:				(6,383)
Remaining in 2019	2,000		$ 70.00	
2020	4,750		$ 70.00	
2021	3,500		$ 70.00	
Total Estimated Fair Value				$ (15,467)

The following table sets forth the average volumes per day associated with the Company's outstanding NGL derivative instruments as of March 31, 2019, the contracted weighted average NGL prices and the estimated fair values:

		Weighted Average Prices ($/bbl)		
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
NGL:				
Swaps - Propane:				$ 13,786
Remaining in 2019	4,500	$ 36.47		
2020	1,500	$ 32.66		
Call options - Propane:				(1,022)
Remaining in 2019	2,100		$ 33.60	
2020	3,150		$ 33.60	
Swaps - Ethane:				1,843
Remaining in 2019	1,000	$ 17.01		
Total Estimated Fair Value				$ 14,607

The following tables summarize the classification and fair value amounts of all commodity derivative instruments on the condensed consolidated balance sheets as of March 31, 2019 and December 31, 2018, as well as the gross recognized derivative assets and liabilities and amounts offset on the condensed consolidated balance sheets:

		March 31, 2019		
($ in thousands)	Condensed Consolidated Balance Sheet Classification	Gross Recognized Fair Value	Amounts Netted on Balance Sheet	Net Recognized Fair Value on Balance Sheet
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative assets	$ 71,172	$ (55,563)	$ 15,609
Natural gas, oil and NGL commodity derivatives	Long-term derivative assets	$ 102,972	$ (84,324)	$ 18,648
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative liabilities	$ (108,070)	$ 55,563	$ (52,507)
Natural gas, oil and NGL commodity derivatives	Long-term derivative liabilities	$ (123,707)	$ 84,324	$ (39,383)

		December 31, 2018		
($ in thousands)	Condensed Consolidated Balance Sheet Classification	Gross Recognized Fair Value	Amounts Netted on Balance Sheet	Net Recognized Fair Value on Balance Sheet
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative assets	$ 117,732	$ (65,328)	$ 52,404
Natural gas, oil and NGL commodity derivatives	Long-term derivative assets	$ 150,349	$ (110,806)	$ 39,543
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative liabilities	$ (66,396)	$ 65,328	$ (1,068)
Natural gas, oil and NGL commodity derivatives	Long-term derivative liabilities	$ (132,247)	$ 110,806	$ (21,441)

The following table summarizes the effects of commodity derivative instruments on the condensed consolidated statements of operations for the periods presented:

		Three Months Ended March 31,	
($ in thousands)	Condensed Consolidated Statements of Operations Presentation	2019	2018
Natural gas, oil and NGL commodity derivatives	Commodity derivative (loss) gain	$ (157,189)	$ 217

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.

Fair Value of Derivative Instruments

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of March 31, 2019 and December 31, 2018. The fair values of the natural gas, oil and NGL commodity derivatives are based primarily on inputs that are derived from observable data at commonly quoted intervals and are therefore classified as Level 2. See Note 6 for further information regarding the Company's commodity derivative instruments.

	Fair value measurements at March 31, 2019 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 34,257	$ —	$ 34,257
Total	$ —	$ 34,257	$ —	$ 34,257
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 91,890	$ —	$ 91,890
Total	$ —	$ 91,890	$ —	$ 91,890

	Fair value measurements at December 31, 2018 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 91,947	$ —	$ 91,947
Total	$ —	$ 91,947	$ —	$ 91,947
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 22,509	$ —	$ 22,509
Total	$ —	$ 22,509	$ —	$ 22,509

Fair Value of Debt

The carrying amounts and estimated fair values of long-term debt as of March 31, 2019 and December 31, 2018 are shown in the table below. The fair values were estimated using Level 2 market data inputs. See Note 5 for further information regarding the Company's long-term debt.

	March 31, 2019		December 31, 2018	
($ in thousands)	Carrying Value	Fair Value	Carrying Value	Fair Value
2022 Notes	$ 959,098	$ 1,067,918	$ 957,993	$ 997,230
2026 Notes	585,208	576,750	584,876	540,000
Credit Facility	925,000	925,000	948,000	948,000
Convertible Notes	90,711	104,225	86,925	99,567
Total	$ 2,560,017	$ 2,673,893	$ 2,577,794	$ 2,584,797

Fair Value Measurement on a Non-recurring Basis

The Company used a discounted cash flow model to estimate the fair value of the natural gas and oil properties acquired in business combinations. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of natural gas and oil properties include the Company's estimates of (i) quantities of natural gas and oil reserves, (ii) future commodity prices, (iii) future operating and development costs, (iv) projections of future timing and rates of production, (v) reserve risk adjustments and (vi) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates. See Note 3, *2018 Acquisitions*, for further discussion of the CNX and Hess Acquisition and the UMD Acquisition.

The key inputs used to estimate the fair value of the natural gas and oil properties acquired in the CNX and Hess Acquisition and the UMD Acquisition are as follows:

Market-based weighted average cost of capital rate	9.0%
Reserve risk factors	10% - 100%
Natural gas price	Three years NYMEX Henry Hub forward curve
Oil price	Three years NYMEX WTI forward curve
NGL price	36% - 46% of oil price
Price escalation after end of forward curve	2.0%

8. Related Party Transactions

Gas Gathering, Firm Transportation, Processing and Commodity Sales Agreements

The Company has entered into certain business relationships with entities in which EMG or First Reserve have control or significant influence. The gathering, processing and transportation (GP&T) expenses incurred and NGL revenues realized with the Company's related parties are presented below for the periods indicated:

		Three Months Ended March 31,	
($ in thousands)	Condensed Consolidated Statements of Operations Presentation	2019	2018
Blue Racer Midstream, LLC[a]	GP&T expenses	$ (17,778)	$ (3,992)
Blue Racer Midstream, LLC[a]	NGL revenues	$ 14,546	$ 360
Crestwood Services, LLC[b]	NGL revenues	$ 13,701	$ —
Jefferson Gas Gathering Company, LLC[c]	GP&T expenses	$ (27,233)	$ (16,746)
MarkWest Utica EMG, LLC[d]	GP&T expenses	$ (8,806)	$ (5,490)
MarkWest Utica EMG, LLC[d]	NGL revenues	$ 4,688	$ 15,472
Ohio Gathering Company, LLC[d]	GP&T expenses	$ (10,974)	$ (7,211)
Ohio River System LLC[e]	GP&T expenses	$ (15,552)	$ (8,313)
Rover Pipeline LLC[f]	GP&T expenses	$ (50,779)	$ (28,489)
Rockies Express Pipeline LLC[g]	GP&T expenses	$ (23,544)	$ (22,556)

The receivables due from or (payables due to) the Company's related parties, excluding any reimbursement to or from working interest and royalty interest owners, where appropriate, or credits for third party volumes, are presented below for the periods indicated:

($ in thousands)	Condensed Consolidated Balance Sheets Classification	March 31, 2019	December 31, 2018
Blue Racer Midstream, LLC[a]	Accounts payable	$ (6,646)	$ (8,304)
Blue Racer Midstream, LLC[a]	Accounts receivable - natural gas, oil and NGL sales	$ 5,865	$ 6,071
Crestwood Services, LLC[b]	Accounts receivable - natural gas, oil and NGL sales	$ 8,393	$ 9,157
Jefferson Gas Gathering Company, LLC[c]	Accounts payable	$ (20,536)	$ (19,649)
MarkWest Utica EMG, LLC[d]	Accounts receivable - natural gas, oil and NGL sales	$ 6,444	$ 1,439
Ohio Gathering Company, LLC[d]	Accounts payable	$ (18,908)	$ (16,919)
Ohio River System LLC[e]	Accounts payable	$ (12,673)	$ (11,010)
Rover Pipeline LLC[f]	Accounts payable	$ (20,579)	$ (20,640)
Rockies Express Pipeline LLC[g]	Accounts payable	$ (9,353)	$ (9,366)

(a) In August 2014, the Company entered into a gas gathering agreement with Blue Racer Midstream, LLC (BRM), and in October 2017, the Company entered into a capacity utilization agreement with BRM. First Reserve has significant influence over BRM through its equity investments in BRM made in December 2018. Additional gas gathering, processing and NGL sales agreements between BRM and third parties were assigned to the Company in June 2014, February 2017 and August 2018.

(b) In March 2018, the Company entered into an NGL sales agreement with Crestwood Services, LLC (Crestwood). First Reserve has significant influence over Crestwood through its indirect equity investment in the general partner of Crestwood Equity Partners, LP. The Company's agreement with Crestwood terminated in March 2019.

(c) In August 2015, the Company entered into a gas gathering agreement with Jefferson Gas Gathering Company, LLC (Jefferson). EMG has significant influence over Jefferson through its equity investment in Jefferson's parent, MarkWest EMG Jefferson Dry Gas Gathering Company, LLC.

(d) In September 2014, the Company entered into a gas gathering agreement with Ohio Gathering Company, LLC (Ohio Gathering). Ohio Gathering is a joint venture of MarkWest Utica EMG, LLC (MWU EMG). EMG has significant influence over Ohio Gathering through its equity investment in MWU EMG. The Company also entered into a gas processing and fractionation agreement with MWU EMG.

(e) In August 2014, the Company entered into a gathering and compression agreement with Ohio River System LLC (ORS). Traverse Midstream Partners LLC (Traverse), an EMG controlled entity, through its subsidiaries owns a 25% interest in ORS. For information regarding the credit support requirements due to ORS, see Note 9, *Pipeline Commitments*.

(f) In June 2014, the Company entered into a firm transportation agreement with Rover Pipeline LLC (Rover). Traverse, through its subsidiaries, owns a 35% interest in Rover. In October 2017, partial transportation services per the Company's agreement with Rover began, and full transportation services provided under the agreement commenced in June 2018. For information regarding the credit support requirements due to Rover, see Note 9, *Pipeline Commitments*.

(g) In April and October 2014, the Company entered into firm transportation agreements with Rockies Express Pipeline LLC (REX). REX is majority owned by Tallgrass Energy Partners, LP (Tallgrass). EMG had significant influence over REX through its indirect equity investments in Tallgrass; however, in March 2019, EMG sold its controlling interest in Tallgrass to a party unrelated to the Company.

9. Commitments and Contingencies

Litigation Matters

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

The Company is defending against certain pending claims, has resolved a number of claims through negotiated settlements and prevailed in various other lawsuits. Based on management's current assessment, the Company believes no pending or threatened lawsuit or dispute relating to the Company's business operations is likely to have a material adverse effect on its 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. For all such pending litigation, as of March 31, 2019, the Company has reserved $9.4 million and associated interest, which is presented as other current liabilities on the condensed consolidated balance sheet.

Environmental Matters

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

Commitments

The following table presents the Company's undiscounted commitments under unconditional purchase obligations, excluding any reimbursement from working interest and royalty interest owners, where appropriate, or credits for third party volumes, that have initial or remaining non-cancelable terms in excess of one year as of March 31, 2019:

($ in thousands)	Pipeline Commitments	Operating Leases	Other Purchase Obligations	Total
Remaining in 2019	$ 462,355	$ 3,395	$ 168	$ 465,918
2020	644,812	4,378	1,273	650,463
2021	662,185	1,010	1,246	664,441
2022	666,382	4	154	666,540
2023	666,089	—	—	666,089
Thereafter	6,853,389	—	—	6,853,389
Total	$ 9,955,212	$ 8,787	$ 2,841	$ 9,966,840

Pipeline Commitments

The Company has entered into certain pipeline capacity commitments with various counterparties in order to facilitate the delivery of its production to market and reduce the impact of possible production curtailments that may arise due to limited capacity. These contracts commit the Company to transport minimum daily natural gas or NGL volumes at negotiated rates or pay specified fees for any deficiencies. The amounts in the table above represent the gross amounts the Company is committed to pay; however, working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. To satisfy credit support requirements for these commitments, the Company has issued letters of credit and/or surety bonds to certain transportation providers, as discussed below.

As discussed in Note 8, *Gas Gathering, Firm Transportation, Processing and Commodity Sales Agreements,* the Company entered into certain firm transportation commitments with ORS and Rover. Pursuant to these commitments, the Company is obligated to provide credit support as defined in each agreement. As of March 31, 2019, the Company had issued $241.3 million in letters of credit to Rover, and $41.0 million in surety bonds were issued on behalf of the Company to ORS to satisfy these credit support obligations. The Company is party to certain firm transportation commitments with other providers for which $81.8 million in letters of credit and $108.7 million in surety bonds have been issued by or on behalf of the Company as of March 31, 2019.

Operating Leases

The Company leases certain equipment and office space. Lease expense related to operating leases totaled $1.2 million during both the three months ended March 31, 2019 and 2018.

Contingency

In November 2017, the Company acquired both producing and non-producing natural gas and oil properties located in the Utica Shale. This acquisition included contingent consideration of up to $15.0 million if the average West Texas Intermediate (WTI) daily price of crude oil is greater than certain pre-defined prices in 2018, 2019 and 2020, respectively. Due to oil prices in 2018, the Company recognized a liability of $5.0 million in 2018, which was paid in January 2019. Due to the significant volatility in oil prices in recent years, it was concluded that no additional accrual was necessary as of March 31, 2019. The Company's joint venture partner is responsible for 20% of any contingent consideration payments made. This contingency will be reassessed quarterly to determine if additional accruals should be recorded in the future.

10. Other Current Liabilities

The Company's other current liabilities consisted of the following as of March 31, 2019 and December 31, 2018:

($ in thousands)	March 31, 2019	December 31, 2018
Drilling and completion accrual	$ 122,911	$ 124,484
Gathering, processing and transportation expense accrual	109,131	106,005
Other	72,860	98,091
Total Other Current Liabilities	$ 304,902	$ 328,580

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

Our Management's Discussion and Analysis of our Financial Condition and Results of Operations (MD&A) should be read in conjunction with our audited consolidated financial statements, the related notes and "Management's Discussion and Analysis of Financial Condition and Results of Operations" for the year ended December 31, 2018, in addition to the unaudited condensed consolidated financial statements and related notes, included within this quarterly report. The following discussion and analysis contains forward-looking statements that involve known and unknown risks, uncertainties and assumptions. The forward-looking statements are not historical facts, but rather reflect our future plans, estimates, beliefs and expected performance. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

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

Overview

We are an independent exploration and production company engaged in the acquisition, exploration and development of natural gas and oil properties in the Utica Shale of the Appalachian Basin in Ohio. We are a wholly-owned subsidiary of Ascent Resources Operating, LLC (Member) and an indirect wholly-owned subsidiary of Ascent Resources, LLC (Parent). We were formed in 2013 by our private equity sponsors, primarily The Energy & Minerals Group and First Reserve Corporation, to utilize our technical expertise to acquire and exploit assets in the Utica Shale. Our asset base is concentrated in southern Ohio, where we target primarily the Point Pleasant interval of the Utica Shale, one of the premier North American natural gas and oil shale plays. Our largely contiguous footprint of approximately 314,000 net leasehold acres lies within the core of the southern Utica Shale and, as supported by our drilling results and those of offset operators, offers development opportunities with predictable and repeatable production profiles, low breakeven costs and industry-leading rates of return. We also own royalty interests on approximately 72,000 fee mineral acres that provide enhanced value without additional capital or operating expenses. We have strategically assembled our position in the southern Utica Shale because of advantageous geological and petrophysical characteristics, including significant overpressure, strong formation seals, favorable rock mechanics (fracturability) and low water saturations in this region, resulting in substantial hydrocarbons in place and well results that are among the most productive in the Utica Shale.

We are continuously focused on enhancing our drilling and completion techniques, minimizing costs and maximizing the ultimate recovery of natural gas, oil and natural gas liquids (NGL) from our assets, with the goal of generating top-tier corporate-level returns. The success of our differentiated operational approach is evident in the results of our operated wells.

2019 Highlights

- In April, the Credit Facility agreement was amended, which most notably affirmed the borrowing base at $2.0 billion, reduced our fees on letters of credit and reduced the amount authorized for letters of credit to $400.0 million.
- Net production increased 76% to 159.1 million cubic feet of natural gas equivalent (mmcfe) for the three months ended March 31, 2019 from 90.4 mmcfe for the three months ended March 31, 2018 as a result of our drilling and completion activity and the completion of the 2018 Acquisitions (defined below). Our net daily production for the first quarter of 2019 averaged 1,768 mmcfe per day and was comprised of approximately 91% natural gas, 3% oil and 6% NGL.
- During the three months ended March 31, 2019, we spud 25 wells, hydraulically fractured 23 wells and turned-in-line 27 new wells.

Non-GAAP Financial Measures

In evaluating our current and future financial results, we focus on production and revenue growth, lease operating expenses and general and administrative expenses. In addition to these metrics, we use adjusted net income, EBITDAX and adjusted EBITDAX (non-GAAP measures) to evaluate our financial results. We define adjusted net income as net income (loss) before impairment of unproved natural gas and oil properties; losses (gains) on purchases or exchanges of debt; changes in fair value of commodity derivatives; changes in fair value of embedded derivative; non-recurring legal expense (benefit); acquisition expenses; incentive units (income) expense; and impairment of other property and equipment. We define EBITDAX as net income (loss) before exploration expenses; depreciation, depletion and amortization (DD&A); and interest expense, net. We define adjusted EBITDAX as EBITDAX before changes in fair value of embedded derivative; losses (gains) on purchases or exchanges of debt; changes in fair value of commodity derivatives; non-recurring legal expense (benefit); acquisition expenses; incentive units (income) expense; impairment of other property and equipment; and other unusual items. These non-GAAP measures are not measures of net income (loss) as determined by United States generally accepted accounting principles (US GAAP).

Non-GAAP measures, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and are not measures of performance calculated in accordance with US GAAP. Non-GAAP measures should not be considered in isolation or as substitutes for operating income, net income or loss, cash flows provided by operating, investing and financing activities or other income or cash flow statement data prepared in accordance with US GAAP. Non-GAAP measures provide no information regarding a company's capital structure, borrowings, interest costs, capital expenditures and working capital movement. Non-GAAP measures do not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, taxes, exploration expenses and other commitments and obligations. However, our management team believes our non-GAAP measures are useful to an investor in evaluating our financial performance because these measures:

- Are widely used by investors in the natural gas and oil industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- Are more comparable to estimates used by analysts;
- Help investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure;
- Excludes one-time items, non-cash items or items whose timing cannot be reasonably estimated; and
- Are used by our management team for various purposes, including as a measure of operating performance, in presentations to our Board of Managers and as a basis for strategic planning and forecasting.

There are significant limitations to using non-GAAP measures as measures of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating non-GAAP measures reported by different companies.

Reconciliations of Non-GAAP Financial Measures

The following table represents a reconciliation of net loss, the most directly comparable US GAAP financial measure, to adjusted net income:

	Three Months Ended March 31,	
($ in thousands)	**2019**	**2018**
Net Loss	$ (85,309)	$ (36,047)
Adjustments to reconcile net loss to adjusted net income:		
Impairment of unproved natural gas and oil properties	38,689	44,106
Change in fair value of commodity derivatives	127,071	10,115
Change in fair value of embedded derivative	(1,138)	336
Incentive units expense (income)	176	(2,188)
Adjusted Net Income (Non-GAAP)	$ 79,489	$ 16,322

The following table represents a reconciliation of net loss, the most directly comparable US GAAP financial measure, to EBITDAX and then to adjusted EBITDAX:

($ in thousands)	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Net Loss	$ (85,309)	$ (36,047)
Adjustments to reconcile net loss to EBITDAX:		
Exploration expenses	39,254	44,726
Natural gas and oil depreciation, depletion and amortization	159,132	95,825
Depreciation and amortization of other assets	765	932
Interest expense, net	21,143	19,577
EBITDAX (Non-GAAP)	134,985	125,013
Adjustments to reconcile EBITDAX to Adjusted EBITDAX:		
Change in fair value of embedded derivative	(1,138)	336
Change in fair value of commodity derivatives	127,071	10,115
Incentive units expense (income)	176	(2,188)
Adjusted EBITDAX (Non-GAAP)	$ 261,094	$ 133,276

We had adjusted net income of $79.5 million and $16.3 million during the three months ended March 31, 2019 and 2018, respectively, demonstrating a year-over-year increase of $63.2 million, or 388%. Adjusted EBITDAX was $261.1 million and $133.3 million during the three months ended March 31, 2019 and 2018, respectively, demonstrating a year-over-year increase of $127.8 million, or 96%. The increases in these non-GAAP measures for the three months ended March 31, 2019 compared to the same period in 2018 are primarily due to a 71% increase in the volume of natural gas produced and a 7% increase in natural gas prices, which were partially offset by net losses on settled natural gas derivatives. Additionally, our oil and NGL production increased by 137% and 165%, respectively, which were only partially offset by decreases in the respective oil and NGL prices.

Liquidity and Capital Resources

Liquidity Overview

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

As of March 31, 2019, we had a cash balance of $10.4 million and availability under our Credit Facility of $751.9 million. In April 2019, the Credit Facility agreement was amended, which most notably affirmed the borrowing base at $2.0 billion, reduced our fees on letters of credit and reduced the amount authorized for letters of credit to $400.0 million. Based on our current cash balance, expected operating cash flows and credit facility availability, we anticipate being able to satisfy all of our financial obligations and commitments for the next twelve months.

We anticipate an increase in our revenues during the remainder of 2019 due to expected increased production related to our drilling and completions program. 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 from operations and the quantities of natural gas, oil and NGL reserves that may be economically produced. Furthermore, in an extended low commodity price environment our ability to generate positive operating cash flows, maintain our natural gas, oil and NGL production and reserves, raise additional capital, sell assets or take any other action to improve liquidity is subject to risks and uncertainties that exist in our industry, some of which we may not be able to anticipate or control.

Sources of Funds

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

($ in thousands)	Three Months Ended March 31, 2019	2018
Cash provided by operating activities	$ 341,739	$ 160,967
Proceeds from credit facility borrowings	325,000	35,000
Proceeds from divestitures of natural gas and oil properties	—	6,564
Total Sources of Cash and Cash Equivalents	$ 666,739	$ 202,531

Net cash flow provided by operating activities was approximately $341.7 million and $161.0 million for the three months ended March 31, 2019 and 2018, respectively. The increase in operating cash flow in 2019 was primarily the result of increases in the volume and price of natural gas produced, which were partially offset by net losses on settled derivatives. Our volumes have increased in 2019 compared to 2018 organically through the drill bit and as a result of acquiring natural gas and oil properties from CNX Resources Corporation, Hess Corporation and Utica Minerals Development, LLC (collectively, the 2018 Acquisitions), as discussed in Note 3, *2018 Acquisitions*, of the notes to our condensed consolidated financial statements included in this report.

During the three months ended March 31, 2019, we borrowed $325.0 million from our Credit Facility and repaid $348.0 million during the same period.

During the three months ended March 31, 2018, we borrowed $35.0 million from our Credit Facility. We also received $6.6 million during the three months ended March 31, 2018 related to a divestiture of natural gas and oil properties in 2017.

Uses of Funds

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

($ in thousands)	Three Months Ended March 31, 2019	2018
Natural Gas and Oil Expenditures:		
Drilling and completion costs	$ (268,518)	$ (190,199)
Acquisitions of natural gas and oil properties	(35,586)	(34,003)
Interest capitalized on unproved leasehold	(14,464)	—
Total Natural Gas and Oil Expenditures	(318,568)	(224,202)
Other Uses of Cash and Cash Equivalents:		
Repayment of credit facility borrowings	(348,000)	—
Cash paid for debt issuance costs	(62)	(1,291)
Additions to other property and equipment	(694)	(67)
Total Other	(348,756)	(1,358)
Total Uses of Cash and Cash Equivalents	$ (667,324)	$ (225,560)

Our drilling and completion costs were $268.5 million and $190.2 million for the three months ended March 31, 2019 and 2018, respectively. The increase is primarily the result of drilling longer laterals, increased working interest and increased completions activity in 2019 compared to 2018. We spud 25 wells, hydraulically fractured 23 wells and turned-in-line 27 new wells during the three months ended March 31, 2019, compared to the same period in 2018 during which we spud 32 wells, hydraulically fractured 26 wells and turned-in-line 11 new wells.

We spent cash of $35.6 million and $34.0 million during the three months ended March 31, 2019 and 2018, respectively, primarily related to the acquisition of leases, arising in the ordinary course of business.

Certain Indebtedness

Credit Facility

The amount available to be borrowed under the Credit Facility is subject to a borrowing base that is required to be redetermined semiannually on or about April 1 and October 1 of each year based on the estimated value and future net cash flows of our proved natural gas, oil and NGL reserves and our commodity derivative positions. As of March 31, 2019, the borrowing base was a fully committed $2.0 billion, of which $500.0 million was authorized for letters of credit, and we had borrowings of $925.0 million and $323.1 million of letters of credit outstanding under the Credit Facility as of that date. In April 2019, the Credit Facility agreement was further amended, which most notably affirmed the borrowing base at $2.0 billion, reduced our fees on letters of credit and reduced the amount authorized for letters of credit to $400.0 million.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the prime rate announced by the administrative agent, (ii) the Federal Reserve Bank of New York federal funds rate plus 0.50% or (iii) the rate for 1-month Eurodollar loans, plus an applicable margin ranging from 0.50% to 1.50% per annum. Eurodollar loans bear interest at a rate per annum equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 1.50% to 2.50% per annum. Due to the weighted average 1-month LIBOR being 2.50% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 4.50% per annum as of March 31, 2019. We may repay any amounts borrowed prior to the maturity date without any premium or penalty. The Credit Facility is secured by liens on substantially all of our properties, including our natural gas and oil properties, and guarantees from our subsidiaries other than any subsidiary that we have designated as an unrestricted subsidiary. As of March 31, 2019, we were in compliance with all applicable financial covenants under the Credit Facility. See Note 5, *Credit Facility*, of the notes to our condensed consolidated financial statements included in this report for further discussion of the terms of the Credit Facility.

Senior Notes

In October 2018, we issued $600.0 million in aggregate principal amount of the 2026 Notes in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The 2026 Notes are due on November 1, 2026, and interest is payable at an annual rate of 7.00% on May 1 and November 1 of each year, beginning with May 1, 2019. We used approximately $577.5 million of the $587.2 million net proceeds from the issuance of the 2026 Notes to exercise our right to redeem 35%, or $525.0 million, of the aggregate principal amount of the 2022 Notes (the Redemption) at a redemption price equal to 110% of the principal thereof. We also paid $1.5 million of accrued and unpaid interest up to, but excluding, the date of the Redemption. We used the remaining net proceeds to repay borrowings under the Credit Facility.

In April 2017, we issued $1.5 billion in aggregate principal amount of senior unsecured notes (2022 Notes) in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The 2022 Notes are due on April 1, 2022, and interest is payable at an annual rate of 10.00% on April 1 and October 1 of each year, which commenced on October 1, 2017. Our net proceeds of approximately $1.47 billion were used to repay and retire all of our outstanding second lien term loans and for general corporate purposes. As of March 31, 2019, we had $975.0 million in aggregate principal amount of the 2022 Notes outstanding as a result of the Redemption.

At any time prior to November 1, 2021, we may redeem up to 40% of the aggregate principal amount of the 2026 Notes at a price equal to 107% of the principal amount, plus accrued and unpaid interest up to, but excluding, the redemption date, with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Additionally, at any time prior to April 1, 2020 for the 2022 Notes or November 1, 2021 for the 2026 Notes (together, the Senior Notes), we may redeem some or all of the Senior Notes subject to a make-whole premium plus accrued and unpaid interest to, but excluding, the redemption date. We may redeem some or all of the Senior Notes at the applicable redemption prices (expressed as percentages of principal amount) set forth in the table below on the dates set forth therein:

Senior Notes	Redemption on or after	Redemption Price
2022 Notes	April 1, 2020	107.500%
2022 Notes	April 1, 2021	105.000%
2022 Notes	October 1, 2021 and thereafter	100.000%
2026 Notes	November 1, 2021	103.500%
2026 Notes	November 1, 2022	102.333%
2026 Notes	November 1, 2023	101.167%
2026 Notes	November 1, 2024 and thereafter	100.000%

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

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

As of March 31, 2019, we were in compliance with all applicable covenants of the 2022 Notes and 2026 Notes indentures. See Note 5, *Senior Notes*, of the notes to our condensed consolidated financial statements included in this report for further discussion of the terms of the 2022 Notes and 2026 Notes.

Convertible Notes

In 2014, we issued $1.0 billion of convertible notes due 2021 (Convertible Notes). Through multiple transactions from 2015 through 2017, we repurchased or otherwise retired $950.3 million in aggregate principal and accrued and unpaid interest of the Convertible Notes, including $11.1 million of outstanding principal and accrued and unpaid interest in March 2017 contributed to us by the Member.

As of March 31, 2019, we had $75.3 million in aggregate principal, including accrued and unpaid interest, of the Convertible Notes outstanding. The Convertible Notes mature on March 1, 2021 and are subordinate to the Senior Notes, which rank senior in right of payment. Interest may be paid in cash or in kind semi-annually in arrears on March 1 and September 1 of each year and is currently payable at an annual rate of 6.50%. We have elected to pay interest in kind on each interest payment date since September 2015. Upon maturity, unless earlier repurchased or converted, we will be required to redeem the Convertible Notes at 153.8% of the outstanding principal value, plus accrued and unpaid interest up to, but not including, the maturity date. We accrete the 53.8% premium to interest expense through the maturity date using the effective interest method.

Conversion of the Convertible Notes into common shares of the qualified public offering issuer (Qualified PO Issuer) following a qualified initial public offering (Qualified PO) is at the option of the noteholders. 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. Following the closing of a Qualified PO, we will have the option to redeem all of the Convertible Notes that were not otherwise converted at a price equal to 100% of the principal of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any. The Convertible Notes also provide for cash redemption upon a change of control event at the option of the holders at a price, including a premium, of 153.8% of the principal amount of the Convertible Notes, plus accrued and unpaid interest up to, but not including, the date of redemption. The Convertible Notes are not redeemable by the holders prior to a change of control or the closing of a Qualified PO.

Contractual Obligations and Off-Balance Sheet Arrangements

We occasionally enter into arrangements that can give rise to contractual obligations and off-balance sheet commitments, such as pipeline transportation commitments, drilling rig commitments, and various other commitments in the ordinary course of business. See Note 9 of the notes to our condensed consolidated financial statements included in this report for further details of our commitments.

New Accounting Pronouncements

See Note 1, *Adopted and Recently Issued Accounting Pronouncements,* of the notes to our condensed consolidated financial statements included in this report for a description of recent accounting pronouncements.

Results of Operations

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Net Production Volumes:		
Natural gas (mmcf)	144,644	84,718
Oil (mbbls)	767	324
NGL (mbbls)	1,641	619
Natural Gas Equivalent (mmcfe)	159,102	90,375
Natural Gas, Oil and NGL Sales ($ in thousands):		
Natural gas	$ 460,378	$ 252,846
Oil	37,543	18,730
NGL	35,442	16,874
Settlements of commodity derivatives	(30,118)	10,332
Change in fair value of commodity derivatives	(127,071)	(10,115)
Total	$ 376,174	$ 288,667
Average Daily Net Production Volumes:		
Natural gas (mmcf/d)	1,607	941
Oil (mbbls/d)	9	4
NGL (mbbls/d)	18	7
Natural Gas Equivalent (mmcfe/d)	1,768	1,004
Average Sales Prices:		
Natural gas ($/mcf)	$ 3.18	$ 2.98
Oil ($/bbl)	$ 48.87	$ 57.76
NGL ($/bbl)	$ 21.59	$ 27.28
Natural Gas Equivalent ($/mcfe)	$ 3.35	$ 3.19
Settlements of commodity derivatives ($/mcfe)	(0.19)	0.11
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.16	$ 3.30
Operating Expenses ($/mcfe):		
Lease operating expenses	$ 0.11	$ 0.15
Gathering, processing and transportation expenses	$ 1.26	$ 1.50
Production and ad valorem taxes	$ 0.05	$ 0.04
General and administrative expenses	$ 0.10	$ 0.11
Natural gas and oil depreciation, depletion and amortization	$ 1.00	$ 1.06
Depreciation and amortization of other assets	$ —	$ 0.01

Natural Gas Sales. During the three months ended March 31, 2019 and 2018, natural gas sales (excluding the effects of derivatives) were $460.4 million and $252.8 million, respectively. During the three months ended March 31, 2019 and 2018, we sold 144.6 bcf and 84.7 bcf of natural gas, at weighted average prices of $3.18 and $2.98 per mcf, respectively (excluding the effects of derivatives). The $207.6 million increase in natural gas sales (excluding the effects of derivatives) in 2019 compared to 2018 was driven by a 71% increase in natural gas production and a 7% increase in the average sales price received for natural gas.

The $99.5 million loss on natural gas derivatives during the three months ended March 31, 2019 was comprised of a $69.3 million decrease in the fair value and $30.2 million of net settlement losses. The $12.0 million gain on natural gas derivatives during the three months ended March 31, 2018 was comprised of $13.4 million of net settlement gains, offset by a $1.4 million decrease in the fair value.

A change in natural gas prices has a significant impact on our sales and cash flows. Assuming our production levels for the three months ended March 31, 2019 remained constant and without considering the effect of derivatives, an increase or decrease of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in sales and cash flows of approximately $14.5 million for the three months ended March 31, 2019.

Oil Sales. During the three months ended March 31, 2019 and 2018, oil sales (excluding the effects of derivatives) were $37.5 million and $18.7 million, respectively. During the three months ended March 31, 2019 and 2018, we sold 767 mbbls and 324 mbbls at weighted average prices of $48.87 and $57.76 per bbl, respectively, (excluding the effects of derivatives). The $18.8 million increase in oil sales (excluding the effects of derivatives) in 2019 compared to 2018 was driven by a 137% increase in oil production, which was partially offset by a 15% decrease in the average sales price received for oil.

The $57.3 million loss on oil derivatives during the three months ended March 31, 2019 was comprised of a $57.5 million decrease in the fair value, offset by $0.2 million of net settlement gains. The $11.8 million loss on oil derivatives during the three months ended March 31, 2018 was comprised of an $8.7 million decrease in the fair value and $3.1 million of net settlement losses.

A change in oil prices has a direct impact on our sales and cash flows. Assuming our production levels for the three months ended March 31, 2019 remained constant and without considering the effects of derivatives, an increase or decrease of $1.00 per barrel of oil sold would have resulted in an increase or decrease in sales and cash flows of approximately $0.8 million for the three months ended March 31, 2019.

NGL Sales. During the three months ended March 31, 2019 and 2018, NGL sales (excluding the effects of derivatives) were $35.4 million and $16.9 million, respectively. During the three months ended March 31, 2019 and 2018, we sold 1,641 mbbls and 619 mbbls, respectively, of NGL at weighted average prices of $21.59 and $27.28 per bbl, respectively, (excluding the effects of derivatives). The $18.5 million increase in NGL sales (excluding the effects of derivatives) in 2019 compared to 2018 was driven by a a 165% increase in NGL production, which was partially offset by a 21% decrease in the average sales price received for NGL.

The $0.3 million loss on NGL derivatives during the three months ended March 31, 2019 was the result of a decrease in the fair value. There were no settlements on NGL derivatives during the three months ended March 31, 2019, and we had no NGL derivative instruments during the same period in 2018.

A change in NGL prices has a direct impact on our sales and cash flows. Assuming our production levels for the three months ended March 31, 2019 remained constant, an increase or decrease of $1.00 per barrel of NGL sold would have resulted in an increase or decrease in sales and cash flows of approximately $1.6 million for the three months ended March 31, 2019.

Lease Operating Expenses. Lease operating expenses were $17.9 million and $13.1 million for the three months ended March 31, 2019 and 2018, respectively. On a per unit basis, lease operating expenses were $0.11 and $0.15 per mcfe during the three months ended March 31, 2019 and 2018, respectively. The per unit decrease from 2018 to 2019 was primarily the result of increased production levels, which was offset by an increase in disposal costs resulting from a higher producing well count during the three months ended March 31, 2019 compared to the three months ended March 31, 2018.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses were $200.1 million and $136.0 million for the three months ended March 31, 2019 and 2018, respectively. On a per unit basis, gathering, processing and transportation expenses were $1.26 and $1.50 per mcfe during the three months ended March 31, 2019 and 2018, respectively. The per unit decrease from 2018 to 2019 was due to increased production levels.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $8.5 million and $3.8 million for the three months ended March 31, 2019 and 2018, respectively. Production taxes have increased as production volumes have increased and were $4.7 million and $2.7 million during the three months ended March 31, 2019 and 2018, respectively. Production taxes are calculated using volume-based formulas that produce higher absolute costs as production increases. On a per unit basis, production taxes remained consistent and were $0.03 per mcfe during the three months ended March 31, 2019 and 2018, respectively. Ad valorem taxes were $3.8 million and $1.1 million during the three months ended March 31, 2019 and 2018, respectively. Ad valorem taxes are assessed annually based on wells producing at the end of the previous year. The amount of tax is based on an appraised value of each well including various factors such as historical production at a well level, state decline curves and prices set by the state.

Exploration Expenses. Exploration expenses were $39.3 million and $44.7 million for the three months ended March 31, 2019 and 2018, respectively. We impaired $38.7 million and $44.1 million during the three months ended March 31, 2019 and 2018, respectively, of unproved natural gas and oil properties for which the leases are expected to expire. As we continue to review our acreage position and high grade our drilling inventory focusing on our core type curve areas, additional leasehold impairments and abandonments may be recorded.

General and Administrative Expenses. General and administrative expenses were $16.3 million and $10.3 million for the three months ended March 31, 2019 and 2018, respectively. On a per unit basis, general and administrative expenses were $0.10 and $0.11 per mcfe during the three months ended March 31, 2019 and 2018, respectively. Total general and administrative expenses have increased in 2019 primarily due to a 13% increase in our employee count and related costs from March 31, 2018 to March 31, 2019. The increase in general and administrative expenses was offset by a 76% increase in production volumes in 2019 compared to 2018, creating the decrease on a per unit basis.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $159.1 million and $95.8 million for the three months ended March 31, 2019 and 2018, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs and the related underlying reserves, was $1.00 and $1.06 per mcfe during the three months ended March 31, 2019 and 2018, respectively. The per unit decrease from 2018 to 2019 was the result of a 68% increase in total proved reserves, which was offset by a 63% increase in net capitalized costs during the same period. Our proved reserves increased organically through the drill bit and through the 2018 Acquisitions.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $0.8 million and $0.9 million for the three months ended March 31, 2019 and 2018, respectively. 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 a field office and other corporate assets.

Interest Expense. Interest expense was $21.1 million and $19.6 million for the three months ended March 31, 2019 and 2018, respectively, detailed as follows along with our weighted average debt outstanding:

	Three Months Ended March 31,	
($ in thousands)	**2019**	**2018**
Interest expense on 2022 Notes	$ 24,375	$ 37,503
Interest expense on 2026 Notes	10,500	—
Interest expense on Credit Facility	16,223	5,740
Interest expense on Convertible Notes	1,200	988
Other	765	844
Amortization of debt discount and issuance costs	5,435	4,601
Capitalized interest	(37,355)	(30,099)
Total Interest Expense, net	$ 21,143	$ 19,577
Weighted Average Debt Outstanding:		
2022 Notes	$ 975,000	$ 1,500,000
2026 Notes	600,000	—
Credit Facility	1,009,178	4,278
Convertible Notes	73,356	69,195
Weighted Average Debt Outstanding	$ 2,657,534	$ 1,573,473

The increase in interest expense for the three months ended March 31, 2019 compared to the same period 2018 was primarily due to an increase in our weighted average borrowings under our Credit Facility in 2019.

Quantitative and Qualitative Disclosure About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, oil and NGL prices, customer credit and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Demand and Price Risk

Our primary market risk exposure is in the prices we receive for our natural gas, oil and NGL production. Approximately 88% of our March 31, 2019 proved reserves were natural gas; therefore, changes in realized natural gas pricing will affect us more than changes in realized oil or NGL pricing. Realized pricing is primarily driven by spot regional market prices applicable to our natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production is volatile and unpredictable, and we expect this volatility to continue in the future. The prices we expect to receive for our natural gas, oil and NGL production will depend on many factors outside of our control, including the supply of, and demand for, natural gas, oil and NGL, the level of economic activity in the United States and globally, the performance of specific industries and the volatility of natural gas, oil and NGL prices at various delivery points. We expect that a decrease in economic activity, in the United States and elsewhere, would adversely affect demand for the natural gas, oil and NGL that we expect to produce. During the three months ended March 31, 2019 and 2018, the average daily Henry Hub spot market price of natural gas was $2.89 per mmbtu and $3.02 per mmbtu, respectively, and the average daily West Texas Intermediate oil price was $54.90 per bbl and $62.89 per bbl, respectively.

To mitigate our exposure to adverse commodity price changes, we utilize commodity derivative instruments. We do not enter into commodity derivative instruments for speculative or trading purposes. As of March 31, 2019, our natural gas, oil and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*. We receive a fixed price for our natural gas, oil or NGL production and pay a variable market price to the counterparty.

- *Call Options*. We sell call options in exchange for a premium, which establish the maximum price we will receive for contracted commodity volumes. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the difference to the counterparty. From time to time, we may sell future call options to obtain more favorable strike prices on swap or collar contracts.

- *Collars*. These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price, we pay the difference between market price and the strike price of the sold call to the counterparty. If the market price falls below the put strike price, we receive the difference between market price and the strike price of the purchased put from the counterparty. If the market price is between the put and the call strike prices, no payments are due to or from either party.

- *Three-Way Collars*. Three-way collars consist of a traditional collar and the sale by us of an additional put option in exchange for more favorable strike prices on purchased put or sold call options.

- *Basis Swaps*. Given that our natural gas production is sold at various delivery points that at times may have material spreads or volatility relative to NYMEX, basis swaps are periodically used at the following basis points to fix the differential between product prices at one market location versus another: Chicago (Citygate), Dawn (Ontario), MichCon, Rex Zone 3, Dominion South, TCO and Tetco M-2. Under these instruments, we receive the fixed price differential and pay the floating market price differential to the counterparty for the contracted volumes.

As of March 31, 2019, we had a net liability commodity derivative position of $57.6 million. The following table sets forth the volumes per day associated with our outstanding natural gas derivative instruments as of March 31, 2019, the contracted weighted average natural gas prices and the estimated fair values:

		Weighted Average Prices ($/mmbtu)				
	Average Volume (mmbtu/d)	Fixed Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Natural gas:						
Swaps:						$ 28,810
Remaining in 2019	1,686,000	$ 2.85				
2020	1,430,000	$ 2.74				
2021	410,000	$ 2.73				
2022	50,000	$ 2.82				
Collars:						2,059
Remaining in 2019	8,000		$ 3.40	$ 2.75		
2020	140,000		$ 3.09	$ 2.59		
2021	10,000		$ 2.91	$ 2.50		
Three-way collars:						(3,574)
2021	270,000		$ 2.91	$ 2.50	$ 2.00	
2022	160,000		$ 3.00	$ 2.50	$ 2.01	
Call options:						(61,168)
Remaining in 2019	94,000		$ 3.00			
2020	250,000		$ 3.00			
2021	335,000		$ 3.02			
2022	260,000		$ 3.04			
2023	170,000		$ 3.00			
Basis swaps:						(22,900)
Remaining in 2019	669,000	$ (0.29)				
2020	706,000	$ (0.37)				
2021	30,000	$ (0.52)				
Total Estimated Fair Value						$ (56,773)

The following table sets forth the volumes per day associated with our outstanding oil derivative instruments as of March 31, 2019, the contracted weighted average oil prices and the estimated fair values:

		Weighted Average Prices ($/bbl)		
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
Oil:				
Swaps:				$ (9,084)
Remaining in 2019	7,000	$ 56.56		
2020	7,500	$ 57.20		
2021	1,000	$ 60.06		
Call options:				(6,383)
Remaining in 2019	2,000		$ 70.00	
2020	4,750		$ 70.00	
2021	3,500		$ 70.00	
Total Estimated Fair Value				$ (15,467)

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of March 31, 2019, the contracted weighted average NGL prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Swap Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
NGL:				
Swaps - Propane:				$ 13,786
Remaining in 2019	4,500	$ 36.47		
2020	1,500	$ 32.66		
Call options - Propane:				(1,022)
Remaining in 2019	2,100		$ 33.60	
2020	3,150		$ 33.60	
Swaps - Ethane:				1,843
Remaining in 2019	1,000	$ 17.01		
Total Estimated Fair Value				$ 14,607

As of March 31, 2019, a $0.10 per mmbtu increase or decrease in natural gas prices would have decreased or increased the fair value of our natural gas derivatives by approximately $90.9 million, respectively. As of March 31, 2019, a $1.00 per bbl increase or decrease in oil prices would have decreased or increased the fair value of our oil derivatives by approximately $5.9 million, respectively. As of March 31, 2019, a $1.00 per bbl increase or decrease in NGL prices would have decreased or increased the fair value of our NGL derivatives by approximately $2.3 million, respectively. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual revenue received from the sale of our production covered by the derivative instrument.

Counterparty Credit Risk

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

Customer Credit Risk

We are subject to credit risk resulting from the concentration of our natural gas, oil and NGL receivables. If our largest customers stopped purchasing natural gas, oil or NGL from us, our revenues could decline and our operating results and financial condition could be harmed; however, we do not believe the loss of any single purchaser would materially impact our operating results, as natural gas, oil and NGL are fungible products with well-established markets and we transact with numerous purchasers in our operating region.

We also have joint interest receivables, which arise from billings to entities that own working 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 but can require these entities to prepay drilling costs. We historically have not incurred losses on our joint interest receivables.

Interest Rate Risk

Borrowings under the Credit Facility bear interest at a variable tiered rate based on facility usage plus the 1-month LIBOR. The Credit Facility is also subject to participation fees associated with the balance of outstanding letters of credit issued. As of March 31, 2019, participation fees were calculated from a variable tiered rate based on facility usage plus the 1-month LIBOR. The weighted average interest rate as of March 31, 2019 for both borrowings and participation fees was 4.50%. The variable component of our interest exposes us to interest rate risk. A 1.00% increase in the LIBOR for the three months ended March 31, 2019 would have resulted in an estimated $3.4 million increase in interest expense on borrowings under the Credit Facility. As of March 31, 2019, the Convertible Notes, 2022 Notes and 2026 Notes bore interest at fixed rates of 6.50%, 10.00% and 7.00%, respectively, resulting in no interest rate risk on such instruments. We had no outstanding interest rate derivatives at March 31, 2019. In April 2019, the LIBOR component of the Credit Facility's participation fee structure associated with letters of credit was eliminated and will therefore no longer subject us to interest rate risk on such fees.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations during 2018 or the three months ended March 31, 2019. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment as natural gas, oil and NGL prices and drilling activity increase.