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

Ascent Resources Utica Holdings, LLC

As of June 30, 2019 and December 31, 2018 and for the Three and Six Months Ended June 30, 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)	June 30, 2019	December 31, 2018
Current Assets:		
Cash and cash equivalents	$ 6,450	$ 11,030
Accounts receivable – natural gas, oil and NGL sales	223,293	401,814
Accounts receivable – joint interest and other	44,657	50,531
Short-term derivative assets	214,087	52,404
Other current assets	5,295	6,135
Total Current Assets	493,782	521,914
Property and Equipment:		
Natural gas and oil properties, based on successful efforts accounting	7,750,826	7,066,947
Other property and equipment	29,171	27,454
Less: accumulated depreciation, depletion and amortization	(1,502,757)	(1,185,772)
Property and Equipment, net	6,277,240	5,908,629
Other Assets:		
Long-term derivative assets	43,035	39,543
Other long-term assets	14,006	16,736
Total Assets	$ 6,828,063	$ 6,486,822
Current Liabilities:		
Accounts payable	$ 81,618	$ 106,839
Revenue payable	136,324	178,111
Accrued interest	36,596	41,510
Short-term derivative liabilities	5,697	1,068
Other current liabilities	333,866	328,580
Total Current Liabilities	594,101	656,108
Long-Term Liabilities:		
Long-term debt, net	2,737,411	2,582,820
Long-term derivative liabilities	3,023	21,441
Other long-term liabilities	7,618	11,356
Total Long-Term Liabilities	2,748,052	2,615,617
Commitments and contingencies (Note 9)		
Member’s Equity	3,485,910	3,215,097
Total Liabilities and Member’s Equity	$ 6,828,063	$ 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 June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Revenues:				
Natural gas	$ 360,136	$ 267,431	$ 820,514	$ 520,277
Oil	65,212	28,203	102,755	46,933
NGL	26,150	17,569	61,592	34,443
Commodity derivative gain (loss)	339,681	(68,587)	182,492	(68,370)
Total Revenues	791,179	244,616	1,167,353	533,283
Operating Expenses:				
Lease operating expenses	16,232	9,904	34,151	23,034
Gathering, processing and transportation expenses	200,176	143,908	400,271	279,879
Production and ad valorem taxes	7,975	4,352	16,447	8,153
Exploration expenses	18,484	32,181	57,738	76,907
General and administrative expenses	14,497	15,159	30,841	25,426
Natural gas and oil depreciation, depletion and amortization	156,376	110,768	315,508	206,593
Depreciation and amortization of other assets	782	953	1,547	1,885
Total Operating Expenses	414,522	317,225	856,503	621,877
Income (Loss) from Operations	376,657	(72,609)	310,850	(88,594)
Other (Expense) Income:				
Interest expense, net	(24,868)	(20,873)	(46,011)	(40,450)
Change in fair value of embedded derivative	2,007	5,994	3,145	5,658
Other income (loss)	2,074	(21)	2,577	(170)
Total Other Expense	(20,787)	(14,900)	(40,289)	(34,962)
Net Income (Loss)	$ 355,870	$ (87,509)	$ 270,561	$ (123,556)

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 June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Balance, Beginning of Period	$ 3,129,964	$ 2,151,146	$ 3,215,097	$ 2,182,500
Contributions from Member	76	215,252	252	219,945
Net income (loss)	355,870	(87,509)	270,561	(123,556)
Balance, End of Period	$ 3,485,910	$ 2,278,889	$ 3,485,910	$ 2,278,889

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)	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Cash Flows from Operating Activities:		
Net income (loss)	$ 270,561	$ (123,556)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	317,055	208,478
Change in fair value of commodity derivatives	(178,962)	90,432
Impairment of unproved natural gas and oil properties	55,139	75,525
Non-cash interest expense	13,787	13,154
Change in fair value of embedded derivative	(3,145)	(5,658)
Other	1,180	(1,434)
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable and other assets	173,885	(86,445)
(Decrease) increase in accounts payable, liabilities and other	(59,272)	110,390
Net Cash Provided by Operating Activities	590,228	280,886
Cash Flows from Investing Activities:		
Drilling and completion costs	(597,712)	(416,007)
Acquisitions of natural gas and oil properties	(145,292)	(151,272)
Proceeds from divestitures of natural gas and oil properties	3,323	6,564
Deposit on natural gas and oil property acquisition	—	(79,200)
Additions to other property and equipment	(1,994)	(676)
Net Cash Used in Investing Activities	(741,675)	(640,591)
Cash Flows from Financing Activities:		
Proceeds from credit facility borrowings	735,000	375,000
Repayment of credit facility borrowings	(588,000)	(95,000)
Cash paid for debt issuance costs	(133)	(4,685)
Contributions from Member	—	215,230
Net Cash Provided by Financing Activities	146,867	490,545
Net (Decrease) Increase in Cash and Cash Equivalents	(4,580)	130,840
Cash and Cash Equivalents, Beginning of Period	11,030	119,215
Cash and Cash Equivalents, End of Period	$ 6,450	$ 250,055
Supplemental disclosures of cash flow information:		
Interest paid, net of capitalized interest and interest paid in kind	$ 38,317	$ 26,259
Supplemental disclosures of significant non-cash investing and financing activities:		
Increase in accrued capital expenditures	$ 11,617	$ 27,095

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, "we", "our" or "us"), 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). 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).

Our accompanying unaudited condensed consolidated financial statements and notes were prepared in accordance with United States generally accepted accounting principles (US GAAP) for interim financial information, and intercompany accounts and balances have been eliminated. Certain disclosures normally included in complete 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 our 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 natural gas liquids (NGL) reserves and their values, future production rates and future costs and expenses are the most significant of our estimates.

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

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 our natural gas, oil or NGL, our revenues could decline, and our operating results and financial condition could be harmed. However, management does not believe the loss of any single customer would materially impact our operating results, as natural gas, oil and NGL are fungible products with well-established markets and we transact with numerous customers 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. 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.

Reclassifications

Certain reclassifications have been made to our June 30, 2018 condensed consolidated financial statements to conform to the presentation used for the June 30, 2019 condensed consolidated financial statements.

Revision

Management has determined that incentive units issued by affiliates of ours 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 our 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, we have revised the condensed consolidated statements of operations for the three and six months ended June 30, 2018 to decrease general and administrative expenses by $2.3 million and $8.6 million, respectively, and have also revised the condensed consolidated statement of Member's equity for the six months ended June 30, 2018 to increase contributions from Member by $1.8 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 our 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 as defined by Topic 842 (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 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. The FASB has issued subsequent updates, including ASU 2018-01, ASU 2018-11 and ASU 2019-01, in order to clarify its original intent under Topic 842 and provide additional guidance for transitional disclosures and practical expedients. 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. We are in the process of evaluating the impact of this ASU on our consolidated financial statements and related disclosures. Based on our preliminary review, we expect to record leases with durations greater than twelve months on our balance sheet along with expanded lease disclosures and internal control changes necessary for adoption.

Subsequent Events

We evaluated our June 30, 2019 condensed consolidated financial statements for material subsequent events through August 12, 2019, the date the condensed consolidated financial statements were available to be issued, and no such events were noted.

2. Revenue from Contracts with Customers

Our revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGL that are extracted from our 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. We generally consider the delivery of each unit (mmbtu, barrel 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. We consider 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) our 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. We record revenue in the month production is delivered to the customer. However, settlement statements for certain natural gas, oil and NGL sales may be received for 30 to 90 days after the date production is delivered.

Under our natural gas sales contracts, we deliver 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 our natural gas. Our sales contracts provide that we generally receive revenue for the sale of our natural gas based on a specific index price adjusted for pricing differentials. We transfer control of the product to the customer at the delivery point and recognize 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 us directly or to the processor under processing contracts. For NGL sold by us directly, the sales contracts provide that the product is delivered to the customer at an agreed upon delivery point and that we generally receive revenue for the sale of our NGL based on a specific index price adjusted for pricing differentials. We transfer control of the product to the customer at the delivery point and recognize 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 us to the processor at the tailgate of the processing plant, and revenue is recognized based on the price received from the processor.

Under our oil sales contracts, oil is sold to the customer from storage tanks near the wellhead, and we receive revenue for the sale of our oil based on a contractually agreed upon index price, net of pricing differentials. We transfer control of the product from the storage tanks to the customer and recognize 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).

We have 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 us from a customer.

Disaggregation of Revenue

Our revenues are comprised solely of revenues from customers and include the sale of natural gas, oil and NGL, which are each presented separately on our condensed consolidated statements of operations. We believe 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 our single geographic location.

Transaction Price Allocated to Remaining Performance Obligations

For our product sales that have a contract term greater than one year, we have 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 our 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 our 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, we have 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 our sales contracts, customers are invoiced after our performance obligations have been satisfied, generally when control of the product has been transferred to the customer, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under ASC 606. At June 30, 2019 and December 31, 2018, receivables from contracts with customers were $223.3 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, we 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, we 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 us from a common equity offering by our Parent. In accordance with the agreements, we paid an aggregate non-refundable deposit of $79.2 million to the sellers, which is presented as a deposit on natural gas and oil property acquisitions on the condensed consolidated statement of cash flows for the six months ended June 30, 2018.

The CNX and Hess Acquisition qualified as a business combination, and as such, we 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, we 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 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 our Parent.

UMD Acquisition. On July 13, 2018, we 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 our Parent. The cash consideration was funded using proceeds contributed to us from a common equity offering by our Parent.

The UMD Acquisition qualified as a business combination, and as such, we 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 our 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 June 30, 2018	Six Months Ended June 30, 2018
Pro forma revenues	$ 303,578	$ 651,158
Pro forma net loss	$ (61,150)	$ (64,999)

4. Property and Equipment

Net property and equipment included the following:

($ in thousands)	June 30, 2019	December 31, 2018
Unproved natural gas and oil properties	$ 1,282,800	$ 1,609,036
Proved natural gas and oil properties	6,468,026	5,457,911
Other property and equipment	29,171	27,454
Total Property and Equipment	7,779,997	7,094,401
Accumulated depreciation, depletion and amortization	(1,502,757)	(1,185,772)
Property and Equipment, net	$ 6,277,240	$ 5,908,629

5. Long-Term Debt

Our long-term debt consisted of the following:

($ in thousands)	June 30, 2019	December 31, 2018
Credit Facility[a]	$ 1,095,000	$ 948,000
Senior notes due 2022[b]	975,000	975,000
Senior notes due 2026[c]	600,000	600,000
Convertible notes due 2021[d]	76,525	74,116
Embedded derivative	1,881	5,026
Net unamortized debt issuance costs	(3,907)	(4,243)
Net unamortized debt discounts	(7,088)	(15,079)
Total Long-Term Debt, net	$ 2,737,411	$ 2,582,820

(a) The interest rate was 4.42% and 4.36% as of June 30, 2019 and December 31, 2018, respectively.
(b) The interest rate was 10.00% as of June 30, 2019 and December 31, 2018.
(c) The interest rate was 7.00% as of June 30, 2019 and December 31, 2018.
(d) The interest rate was 6.50% as of June 30, 2019 and December 31, 2018.

Credit Facility

In 2017, 2018 and 2019, we amended the April 2017 credit agreement for our senior secured revolving credit facility (Credit Facility). The amended $2.5 billion Credit Facility matures on December 31, 2021, and as of June 30, 2019, it had a fully committed borrowing base of $2.0 billion, of which $400.0 million was authorized for letters of credit. The Credit Facility is secured by liens on substantially all of our assets, including our natural gas and oil properties. The amount available to be borrowed under our 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 the value of our commodity hedge positions. Additionally, we may request an interim redetermination of the borrowing base in certain circumstances, including acquisitions of proved reserves in excess of certain thresholds. As of June 30, 2019, we had borrowings of approximately $1.1 billion and $315.6 million of letters of credit outstanding under the Credit Facility.

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. All of our borrowings under our Credit Facility are Eurodollar loans as of June 30, 2019. Due to the weighted average 1-month LIBOR being 2.42% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 4.42% per annum as of June 30, 2019. We may repay any amounts borrowed prior to the maturity date without any premium or penalty.

Under the Credit Facility agreement, we are subject to commitment fees payable to the administrative agent for the unutilized portion of our available borrowing base, the rate of which ranges from 0.375% to 0.50% based on Credit Facility utilization. Additionally, we are 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. We are 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 and six months ended June 30, 2019 and 2018, we incurred $2.9 million, $5.3 million, $7.8 million and $11.0 million, respectively, in commitment, participation and fronting fees on letters of credit outstanding and $12.1 million, $2.0 million, $23.5 million and $2.1 million, respectively, in interest on principal borrowings under the Credit Facility, which are recorded as interest expense on the condensed consolidated statements of operations.

The Credit Facility contains restrictive covenants including, but not limited to, restrictions on our 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 us to maintain the following two financial ratios: 1) a consolidated leverage ratio, which requires us 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 us 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 June 30, 2019, we were in compliance with the financial covenants of the Credit Facility.

As of June 30, 2019, we had $13.8 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.

Senior Notes

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 from the issuance of the 2022 Notes were approximately $1.47 billion. The proceeds were used to repay and retire all of our outstanding second lien term loans and for general corporate purposes. Our obligations under the 2022 Notes are fully and unconditionally guaranteed, jointly and severally, by any of our current and future material subsidiaries. The 2022 Notes are governed by an indenture containing covenants limiting, among other things, our 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. We were in compliance with all applicable covenants under the indenture as of June 30, 2019.

In October 2018, we 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, which began May 1, 2019. We used approximately $577.5 million of the $587.2 million net proceeds 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 and used the remaining net proceeds to repay borrowings under the Credit Facility. Our obligations under the 2026 Notes are fully and unconditionally guaranteed, jointly and severally, by any of our current and future material subsidiaries. The 2026 Notes are governed by an indenture containing covenants limiting, among other things, our 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. We were in compliance with all applicable covenants under the indenture as of June 30, 2019.

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 up 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 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 we repurchased the notes from the holder.

The Senior Notes are senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured debt, and the Senior Notes will rank senior in right of payment to all of 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.

In connection with the issuance and sale of the 2022 Notes, we entered into a registration rights agreement with the initial purchasers. Pursuant to the registration rights agreement, we have agreed to file a registration statement with the United States Securities and Exchange Commission subsequent to an initial public offering of our equity so that the holders may exchange the 2022 Notes for registered notes that have substantially identical terms. In addition, we have agreed to exchange the guarantee related to the 2022 Notes for a registered guarantee having substantially the same terms. We 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 we fail to comply with certain obligations to register the 2022 Notes, then for each 90-day period beginning immediately following such failure, the interest rate on the 2022 Notes will increase by 0.25% per annum, 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%.

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 contributed to us by the Member.

As of June 30, 2019, we had $76.5 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.

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 $1.9 million and $5.0 million as of June 30, 2019 and December 31, 2018, respectively.

Interest Expense

Interest expense was comprised of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
($ in thousands)	2019	2018	2019	2018
Interest expense	$ 51,997	$ 46,583	$ 105,060	$ 91,658
Long-term debt accretion expense	4,111	3,660	7,990	7,203
Deferred debt issuance cost amortization	1,565	1,850	3,121	2,908
Capitalized interest	(32,805)	(31,220)	(70,160)	(61,319)
Total Interest Expense, net	$ 24,868	$ 20,873	$ 46,011	$ 40,450

6. Commodity Derivative Instruments

We use commodity derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our anticipated operating cash flow against significant market movements or volatility. We do not use commodity derivative instruments for speculative or trading purposes. As of June 30, 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 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 our sale 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 relative to NYMEX: 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.

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 we have not elected hedge accounting for any of our commodity derivative instruments. By using commodity derivative instruments, we are exposed to credit risk associated with our hedge counterparties. To minimize such risk, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty. Also, we only enter into derivative contracts with counterparties that are creditworthy, and such creditworthiness is subject to periodic review.

The following table sets forth the average volumes per day associated with our outstanding natural gas derivative instruments as of June 30, 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:						$ 284,562
Remaining in 2019	1,784,000	$ 2.84				
2020	1,430,000	$ 2.74				
2021	450,000	$ 2.73				
2022	50,000	$ 2.82				
2023	100,000	$ 2.70				
Collars:						10,125
Remaining in 2019	7,500		$ 3.40	$ 2.75		
2020	140,000		$ 3.09	$ 2.59		
2021	10,000		$ 2.91	$ 2.50		
Three-way collars:						2,950
2021	270,000		$ 2.91	$ 2.50	$ 2.00	
2022	160,000		$ 3.00	$ 2.50	$ 2.01	
Call options:						(50,129)
Remaining in 2019	140,000		$ 3.00			
2020	250,000		$ 3.00			
2021	335,000		$ 3.02			
2022	260,000		$ 3.04			
2023	170,000		$ 3.00			
Basis swaps:						(15,363)
Remaining in 2019	691,000	$ (0.31)				
2020	747,000	$ (0.36)				
2021	100,000	$ (0.52)				
Total Estimated Fair Value						$ 232,145

The following table sets forth the average volumes per day associated with our outstanding oil derivative instruments as of June 30, 2019, the contracted weighted average oil prices and the estimated fair values:

		Weighted Average Prices ($/bbl)				
	Average Volume (bbl/d)	Fixed Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Oil:						
Swaps:						$ 1,821
Remaining in 2019	7,000	$ 56.92				
2020	4,500	$ 56.09				
2021	2,000	$ 58.42				
Three-way collars:						314
2021	1,000		$ 65.30	$ 52.50	$ 42.50	
Call options:						(4,149)
Remaining in 2019	2,000		$ 70.00			
2020	4,750		$ 70.00			
2021	3,500		$ 70.00			
Total Estimated Fair Value						$ (2,014)

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of June 30, 2019, the contracted weighted average NGL prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Fixed Price	Weighted Average Prices ($/bbl) Sold Call Strike Price	Fair Value ($ in thousands)
NGL:				
Swaps - Propane:				$ 17,337
Remaining in 2019	4,500	$ 36.47		
2020	3,000	$ 30.07		
Call options - Propane:				(614)
Remaining in 2019	3,150		$ 33.60	
2020	3,150		$ 33.60	
Swaps - Ethane:				1,548
Remaining in 2019	1,000	$ 17.01		
Total Estimated Fair Value				$ 18,271

The following tables summarize the classification and fair value amounts of all commodity derivative instruments on the condensed consolidated balance sheets as of June 30, 2019 and December 31, 2018, as well as the gross recognized derivative assets and liabilities and amounts offset on the condensed consolidated balance sheets:

($ in thousands)	Condensed Consolidated Balance Sheet Classification	June 30, 2019 Gross Recognized Fair Value	June 30, 2019 Amounts Netted on Balance Sheet	June 30, 2019 Net Recognized Fair Value on Balance Sheet
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative assets	$ 263,437	$ (49,350)	$ 214,087
Natural gas, oil and NGL commodity derivatives	Long-term derivative assets	$ 141,317	$ (98,282)	$ 43,035
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative liabilities	$ 55,047	$ (49,350)	$ 5,697
Natural gas, oil and NGL commodity derivatives	Long-term derivative liabilities	$ 101,305	$ (98,282)	$ 3,023

($ in thousands)	Condensed Consolidated Balance Sheet Classification	December 31, 2018 Gross Recognized Fair Value	December 31, 2018 Amounts Netted on Balance Sheet	December 31, 2018 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:

($ in thousands)	Condensed Consolidated Statements of Operations Presentation	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Natural gas, oil and NGL commodity derivatives	Commodity derivative gain (loss)	$339,681	$ (68,587)	$182,492	$ (68,370)

7. Fair Value Measurements

We use 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 our 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 June 30, 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 our commodity derivative instruments.

	Fair value measurements at June 30, 2019 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 257,122	$ —	$ 257,122
Total	$ —	$ 257,122	$ —	$ 257,122
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 8,720	$ —	$ 8,720
Total	$ —	$ 8,720	$ —	$ 8,720

	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 June 30, 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 our long-term debt.

	June 30, 2019		December 31, 2018	
($ in thousands)	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$ 1,095,000	$ 1,095,000	$ 948,000	$ 948,000
2022 Notes	960,232	1,032,184	957,993	997,230
2026 Notes	585,575	547,500	584,876	540,000
Convertible Notes	94,723	96,997	86,925	99,567
Total	$ 2,735,530	$ 2,771,681	$ 2,577,794	$ 2,584,797

Fair Value Measurement on a Non-recurring Basis

We 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 our estimates of (i) quantities of natural gas, oil and NGL 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

In the normal course of our business, we have entered into certain business relationships with entities in which EMG or First Reserve have control or significant influence through their equity investments. These relationships include agreements for the sale of our NGL production and the gathering, processing and transportation of our natural gas and NGL production. The NGL revenues recognized under such agreements were $25.5 million, $15.6 million, $58.5 million and $31.1 million during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. As of June 30, 2019 and December 31, 2018, we had accounts receivable – natural gas, oil and NGL sales of $11.1 million and $16.7 million, respectively, due from these purchasers. We also incurred gathering, processing and transportation expenses of $133.4 million, $96.7 million, $288.0 million and $185.5 million during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. As of June 30, 2019 and December 31, 2018, we had accounts payable of $80.0 million and $85.9 million, respectively, due to companies associated with these agreements. For information regarding the credit support requirements due to certain related parties, see Note 9, *Pipeline Commitments*.

9. Commitments and Contingencies

Litigation Matters

We are 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. We continually assess 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. We will continue to monitor the impact that litigation could have on us and will assess the impact of future events. Legal defense costs are accounted for in the period the costs are incurred.

We are defending against certain pending claims, have resolved a number of claims through negotiated settlements and have prevailed in various other lawsuits. Based on management's current assessment, we believe no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our 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 June 30, 2019, we have reserved $9.4 million and associated interest, which is presented as other current liabilities on the condensed consolidated balance sheet.

Environmental Matters

We are 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, we are 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 us.

Commitments

The following table presents our undiscounted commitments under unconditional purchase obligations, excluding any reimbursement from working interest and royalty interest owners, that have initial or remaining non-cancelable terms in excess of one year as of June 30, 2019:

($ in thousands)	Pipeline Commitments	Operating Leases	Other Purchase Obligations	Total
Remaining in 2019	$ 309,698	$ 4,591	$ 128	$ 314,417
2020	645,655	10,148	1,347	657,150
2021	665,883	1,532	1,320	668,735
2022	670,372	65	154	670,591
2023	670,079	—	—	670,079
Thereafter	6,868,351	—	—	6,868,351
Total	$ 9,830,038	$ 16,336	$ 2,949	$ 9,849,323

Pipeline Commitments

We have entered into certain pipeline capacity commitments with various counterparties in order to facilitate the delivery of our production to market and reduce the impact of possible production curtailments that may arise due to limited capacity. Through these contracts, we are committed 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 we are 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, we have issued either letters of credit or surety bonds, and in some cases both, to certain transportation providers, as discussed below.

As discussed in Note 8, we entered into certain firm transportation commitments with entities affiliated with EMG and First Reserve. Pursuant to certain of these commitments, we are obligated to provide credit support as defined in each agreement. To satisfy these credit support obligations, $315.6 million in letters of credit and $154.2 million in surety bonds were issued by us or on our behalf as of June 30, 2019. Our credit support as of June 30, 2019 includes $241.3 million in letters of credit and $41.0 million in surety bonds that have been issued by us or on our behalf to related parties.

Operating Leases

We lease certain drilling rigs, commercial vehicles, equipment and office space as part of our operations. See Note 1, *Adopted and Recently Issued Accounting Pronouncements*, for further discussion of our leases and the expected impact of Topic 842.

Contingency

In November 2017, we 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 exceeding the contingency threshold in 2018, we recognized a liability of $5.0 million in 2018, which was paid in January 2019. Due to recent oil prices exceeding the contingency threshold in 2019, we reserved $5.0 million as of June 30, 2019, which is presented as other current liabilities on the condensed consolidated balance sheet. The contingent payment is due in January 2020 if WTI prices exceed the pre-defined threshold. Our 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

Our other current liabilities consisted of the following as of June 30, 2019 and December 31, 2018:

($ in thousands)	June 30, 2019	December 31, 2018
Drilling and completion cost accrual	$ 148,333	$ 124,484
Gathering, processing and transportation expense accrual	114,818	106,005
Other	70,715	98,091
Total Other Current Liabilities	$ 333,866	$ 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 348,000 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 76,000 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

During the three months ended June 30, 2019, we achieved the following financial and operating results:

- Net production increased 53% to 159.6 million cubic feet of natural gas equivalent (mmcfe) from 104.5 mmcfe for the three months ended June 30, 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 three months ended June 30, 2019 averaged 1,753 mmcfe per day and was comprised of approximately 89% natural gas, 5% oil and 6% NGL.
- Net income increased by $443.4 million to $355.9 million from a net loss of $87.5 million during the three months ended June 30, 2018. Additionally, adjusted net income (defined below) increased by $45.6 million, or 243%, to $64.4 million for the three months ended June 30, 2019 from $18.8 million for the three months ended June 30, 2018, and adjusted EBITDAX (defined below) increased by $96.2 million, or 63%, to $248.4 million for the three months ended June 30, 2019 from $152.2 million during the three months ended June 30, 2018.
- We spud 23 wells, hydraulically fractured 37 wells and turned-in-line 38 new wells.
- 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.

During the six months ended June 30, 2019, we achieved the following financial and operating results:

- Net production increased 64% to 318.7 mmcfe from 194.8 mmcfe for the six months ended June 30, 2018 as a result of our drilling and completion activity and the completion of the 2018 Acquisitions. Our net daily production for the six months ended June 30, 2019 averaged 1,761 mmcfe per day and was comprised of approximately 90% natural gas, 4% oil and 6% NGL.

- Net income increased by $394.2 million to $270.6 million for the six months ended June 30, 2019 from a net loss of $123.6 million during the same period in 2018. Additionally, adjusted net income increased by $108.7 million, or 310%, to $143.8 million for the six months ended June 30, 2019 from $35.1 million for the same period in 2018, and adjusted EBITDAX increased by $224.1 million, or 79%, to $509.5 million for the six months ended June 30, 2019 from $285.4 million during the same period in 2018.

- We spud 48 wells, hydraulically fractured 60 wells and turned-in-line 65 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; and other unusual items. These non-GAAP measures, as used and defined by us, are not measures of performance as determined by United States generally accepted accounting principles (US GAAP) and may not be comparable to similarly titled measures employed by other companies.

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 income (loss), the most directly comparable US GAAP financial measure, to adjusted net income:

($ in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Net Income (Loss)	$ 355,870	$ (87,509)	$ 270,561	$ (123,556)
Adjustments to reconcile net income (loss) to adjusted net income:				
Impairment of unproved natural gas and oil properties	16,450	31,419	55,139	75,525
Change in fair value of commodity derivatives	(306,033)	80,317	(178,962)	90,432
Change in fair value of embedded derivative	(2,007)	(5,994)	(3,145)	(5,658)
Incentive units expense (income)	76	581	252	(1,607)
Adjusted Net Income (Non-GAAP)	$ 64,356	$ 18,814	$ 143,845	$ 35,136

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

($ in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Net Income (Loss)	$ 355,870	$ (87,509)	$ 270,561	$ (123,556)
Adjustments to reconcile net income (loss) to EBITDAX:				
Exploration expenses	18,484	32,181	57,738	76,907
Natural gas and oil depreciation, depletion and amortization	156,376	110,768	315,508	206,593
Depreciation and amortization of other assets	782	953	1,547	1,885
Interest expense, net	24,868	20,873	46,011	40,450
EBITDAX (Non-GAAP)	556,380	77,266	691,365	202,279
Adjustments to reconcile EBITDAX to Adjusted EBITDAX:				
Change in fair value of embedded derivative	(2,007)	(5,994)	(3,145)	(5,658)
Change in fair value of commodity derivatives	(306,033)	80,317	(178,962)	90,432
Incentive units expense (income)	76	581	252	(1,607)
Adjusted EBITDAX (Non-GAAP)	$ 248,416	$ 152,170	$ 509,510	$ 285,446

Adjusted net income was $64.4 million and $18.8 million for the three months ended June 30, 2019 and 2018, respectively, an increase of 243%, and adjusted EBITDAX was $248.4 million and $152.2 million for the three months ended June 30, 2019 and 2018, respectively, an increase of 63%. Adjusted net income was $143.8 million and $35.1 million for the six months ended June 30, 2019 and 2018, respectively, an increase of 310%, and adjusted EBITDAX was $509.5 million and $285.4 million for the six months ended June 30, 2019 and 2018, respectively, an increase of 79%. The increases in these non-GAAP measures for the three and six months ended June 30, 2019 compared to the same periods in 2018 are primarily due to increases in the volumes of natural gas produced during these periods of 45% and 57%, respectively, and improvements to our gathering, processing and transportation expenses on a per unit basis, which were partially offset by decreases in our average realized sales prices. Additionally, our oil and NGL production increased by 173% and 164%, respectively, during the three months ended June 30, 2019 compared to the same period in 2018 and 158% and 164%, respectively, during the six months ended June 30, 2019 compared to the same period in 2018.

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.

As of June 30, 2019, we had a cash balance of $6.5 million and availability under our Credit Facility of $589.4 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.

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. In order to partially mitigate our exposure to these price risks, we maintain a hedging program for our natural gas, oil and NGL production. For further discussion of our commodity derivative instruments, see Note 6 of the notes to our condensed consolidated financial statements included in this report.

Sources of Funds

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

	Six Months Ended June 30,	
($ in thousands)	2019	2018
Cash provided by operating activities	$ 590,228	$ 280,886
Proceeds from credit facility borrowings	735,000	375,000
Contributions from Member	—	215,230
Proceeds from divestitures of natural gas and oil properties	3,323	6,564
Total Sources of Cash and Cash Equivalents	$ 1,328,551	$ 877,680

Net cash flow provided by operating activities was approximately $590.2 million and $280.9 million for the six months ended June 30, 2019 and 2018, respectively. The increase in operating cash flow in 2019 was primarily the result of increases in the volumes of natural gas, oil and NGL produced, which were partially offset by decreases in our average realized sales price. 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 six months ended June 30, 2019, we borrowed $735.0 million from our Credit Facility and repaid $588.0 million during the same period.

During the six months ended June 30, 2018, we borrowed $375.0 million from our Credit Facility and repaid $95.0 million during the same period. We received $215.2 million in cash contributions from equity capital raised by our Parent during the six months ended June 30, 2018 to fund a portion of the cash consideration of the 2018 Acquisitions.

Uses of Funds

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

($ in thousands)	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Natural Gas and Oil Expenditures:		
Drilling and completion costs	$ 597,712	$ 416,007
Acquisitions of natural gas and oil properties	91,261	105,610
Interest capitalized on unproved leasehold	54,031	45,662
Deposit on natural gas and oil property acquisition	—	79,200
Total Natural Gas and Oil Expenditures	743,004	646,479
Other Uses of Cash and Cash Equivalents:		
Repayment of credit facility borrowings	588,000	95,000
Cash paid for debt issuance costs	133	4,685
Additions to other property and equipment	1,994	676
Total Other	590,127	100,361
Total Uses of Cash and Cash Equivalents	$ 1,333,131	$ 746,840

Our drilling and completion costs were $597.7 million and $416.0 million for the six months ended June 30, 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 48 wells, hydraulically fractured 60 wells and turned-in-line 65 new wells during the six months ended June 30, 2019, compared to the same period in 2018 during which we spud 61 wells, hydraulically fractured 55 wells and turned-in-line 52 new wells.

We spent cash of $91.3 million and $105.6 million during the six months ended June 30, 2019 and 2018, respectively, primarily related to the acquisition of leases arising in the ordinary course of business. We paid a non-refundable deposit of $79.2 million related to the CNX and Hess Acquisition during the six months ended June 30, 2018.

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. 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. As of June 30, 2019, the borrowing base was a fully committed $2.0 billion, and we had borrowings of approximately $1.1 billion and $315.6 million of letters of credit outstanding under the Credit Facility.

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, and all of our borrowings under our Credit Facility are Eurodollar loans as of June 30, 2019. Due to the weighted average 1-month LIBOR being 2.42% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 4.42% per annum as of June 30, 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 June 30, 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 June 30, 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 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 June 30, 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 contributed to us by the Member.

As of June 30, 2019, we had $76.5 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 June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Net Production Volumes:				
Natural gas (mmcf)	142,115	97,931	286,759	182,649
Oil (mbbls)	1,230	451	1,997	775
NGL (mbbls)	1,676	636	3,317	1,255
Natural Gas Equivalent (mmcfe)	159,552	104,458	318,654	194,833
Natural Gas, Oil and NGL Sales ($ in thousands):				
Natural gas	$ 360,136	$ 267,431	$ 820,514	$ 520,277
Oil	65,212	28,203	102,755	46,933
NGL	26,150	17,569	61,592	34,443
Settlements of commodity derivatives	33,648	11,730	3,530	22,062
Change in fair value of commodity derivatives	306,033	(80,317)	178,962	(90,432)
Total	$ 791,179	$ 244,616	$ 1,167,353	$ 533,283
Average Daily Net Production Volumes:				
Natural gas (mmcf/d)	1,562	1,076	1,584	1,009
Oil (mbbls/d)	14	5	11	4
NGL (mbbls/d)	18	7	18	7
Natural Gas Equivalent (mmcfe/d)	1,753	1,148	1,761	1,076
Average Sales Prices:				
Natural gas ($/mcf)	$ 2.53	$ 2.73	$ 2.86	$ 2.85
Oil ($/bbl)	$ 53.01	$ 62.48	$ 51.45	$ 60.56
NGL ($/bbl)	$ 15.60	$ 27.61	$ 18.57	$ 27.44
Natural Gas Equivalent ($/mcfe)	$ 2.83	$ 3.00	$ 3.09	$ 3.09
Settlements of commodity derivatives ($/mcfe)	0.21	0.11	0.01	0.11
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.04	$ 3.11	$ 3.10	$ 3.20
Operating Expenses ($/mcfe):				
Lease operating expenses	$ 0.10	$ 0.09	$ 0.11	$ 0.12
Gathering, processing and transportation expenses	$ 1.25	$ 1.38	$ 1.26	$ 1.44
Production and ad valorem taxes	$ 0.05	$ 0.04	$ 0.05	$ 0.04
General and administrative expenses	$ 0.09	$ 0.15	$ 0.10	$ 0.13
Natural gas and oil depreciation, depletion and amortization	$ 0.98	$ 1.06	$ 0.99	$ 1.06
Depreciation and amortization of other assets	$ —	$ 0.01	$ —	$ 0.01

Natural Gas Sales. During the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, natural gas sales (excluding the effects of derivatives) were $360.1 million, $267.4 million, $820.5 million and $520.3 million, respectively. During the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, we sold 142.1 bcf, 97.9 bcf, 286.8 bcf and 182.6 bcf of natural gas, at weighted average prices of $2.53, $2.73, $2.86 and $2.85 per mcf, respectively (excluding the effects of derivatives). The $92.7 million increase in natural gas sales (excluding the effects of derivatives) for the three months ended June 30, 2019 compared to the three months ended June 30, 2018 was driven by a 45% increase in natural gas production, which was partially offset by a 7% decrease in the average sales price received for natural gas. The $300.2 million increase in natural gas sales (excluding the effects of derivatives) in the six months ended June 30, 2019 compared to the six months ended June 30, 2018 was driven by a 57% increase in natural gas production.

We had a $316.3 million gain on natural gas derivatives during the three months ended June 30, 2019 comprised of a $288.9 million increase in the fair value and $27.4 million of net settlement gains. We had a $27.8 million loss on natural gas derivatives during the three months ended June 30, 2018 comprised of a $45.2 million decrease in the fair value, partially offset by $17.4 million of net settlement gains. We had a $216.8 million gain on natural gas derivatives during the six months ended June 30, 2019 comprised of a $219.7 million increase in the fair value, partially offset by $2.9 million of net settlement losses. We had a $15.8 million loss on natural gas derivatives during the six months ended June 30, 2018 comprised of a $46.6 million decrease in the fair value, partially offset by $30.8 million of net settlement gains.

A change in natural gas prices has a significant impact on our sales and cash flows. Assuming our production levels for the three and six months ended June 30, 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 $14.2 million and $28.7 million for the three and six months ended June 30, 2019, respectively.

Oil Sales. During the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, oil sales (excluding the effects of derivatives) were $65.2 million, $28.2 million, $102.8 million and $46.9 million, respectively. During the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, we sold 1,230 mbbls, 451 mbbls, 1,997 mbbls and 775 mbbls at weighted average prices of $53.01, $62.48, $51.45 and $60.56 per bbl, respectively, (excluding the effects of derivatives). The $37.0 million increase in oil sales (excluding the effects of derivatives) for the three months ended June 30, 2019 compared to the three months ended June 30, 2018 was driven by a 173% increase in oil production, partially offset by a 15% decrease in the average sales price received for oil. The $55.9 million increase in oil sales (excluding the effects of derivatives) in the six months ended June 30, 2019 compared to the six months ended June 30, 2018 was driven by a 158% increase in oil production, which was partially offset by a 15% decrease in the average sales price received for oil.

We had a $13.5 million gain on oil derivatives during the three months ended June 30, 2019 comprised of a $13.5 million increase in the fair value. We had a $40.8 million loss on oil derivatives during the three months ended June 30, 2018 comprised of a $35.1 million decrease in fair value and $5.7 million of net settlement losses. We had a $43.8 million loss on oil derivatives during the six months ended June 30, 2019 comprised of a $44.0 million decrease in the fair value, partially offset by $0.2 million of net settlement gains. We had a $52.5 million loss on oil derivatives during the six months ended June 30, 2018 comprised of a $43.8 million decrease in the fair value and $8.7 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 and six months ended June 30, 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 $1.2 million and $2.0 million for the three and six months ended June 30, 2019, respectively.

NGL Sales. During the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, NGL sales (excluding the effects of derivatives) were $26.2 million, $17.6 million, $61.6 million and $34.4 million, respectively. During the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, we sold 1,676 mbbls, 636 mbbls, 3,317 mbbls and 1,255 mbbls at weighted average prices of $15.60, $27.61, $18.57 and $27.44 per bbl, respectively, (excluding the effects of derivatives). The $8.6 million increase in NGL sales (excluding the effects of derivatives) for the three months ended June 30, 2019 compared to the three months ended June 30, 2018 was driven by a 164% increase in NGL production, partially offset by a 43% decrease in the average sales price received for NGL. The $27.2 million increase in NGL sales (excluding the effects of derivatives) in the six months ended June 30, 2019 compared to the six months ended June 30, 2018 was driven by a 164% increase in NGL production, which was partially offset by a 32% decrease in the average sales price received for NGL.

We had a $9.8 million gain on NGL derivatives during the three months ended June 30, 2019 comprised of a $3.7 million increase in the fair value and $6.1 million of net settlement gains. We had a $9.5 million gain on NGL derivatives during the six months ended June 30, 2019 comprised of a $3.4 million increase in the fair value and $6.1 million of net settlement gains. We did not have any NGL derivative instruments during the three or six months ended June 30, 2018.

A change in NGL prices has a direct impact on our sales and cash flows. Assuming our production levels for the three and six months ended June 30, 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 $1.7 million and $3.3 million for the three and six months ended June 30, 2019, respectively.

Lease Operating Expenses. Lease operating expenses were $16.2 million, $9.9 million, $34.2 million and $23.0 million for the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. On a per unit basis, lease operating expenses were $0.10, $0.09, $0.11 and $0.12 per mcfe during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. Total lease operating expenses increased as a result of an increase in disposal costs from an increase in producing wells during the three and six months ended June 30, 2019 compared to the same periods in 2018.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses were $200.2 million, $143.9 million, $400.3 million and $279.9 million for the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. On a per unit basis, gathering, processing and transportation expenses were $1.25, $1.38, $1.26 and $1.44 per mcfe during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. The per unit decrease for the three and six months ended June 30, 2019 compared to the same periods in 2018 was due to increased production levels which more fully utilized our firm transportation commitments.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $8.0 million, $4.4 million, $16.4 million and $8.2 million for the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. Production taxes have increased as production volumes have increased and were $4.8 million, $3.3 million, $9.4 million and $6.0 million during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 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 flat and were $0.03 per mcfe during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. Ad valorem taxes were $3.2 million, $1.1 million, $7.0 million and $2.2 million during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 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 rates set by the state. As such, total ad valorem taxes have increased due to an increase in producing wells.

Exploration Expenses. Exploration expenses were $18.5 million, $32.2 million, $57.7 million and $76.9 million for the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. During the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, we impaired $16.5 million, $31.4 million, $55.1 million and $75.5 million, 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 $14.5 million, $15.2 million, $30.8 million and $25.4 million for the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. On a per unit basis, general and administrative expenses were $0.09, $0.15, $0.10 and $0.13 per mcfe during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. General and administrative expenses for the three and six months ended June 30, 2019 compared to the same periods in 2018 have decreased on a per unit basis primarily as a result of increased production.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $156.4 million, $110.8 million, $315.5 million and $206.6 million for the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs and the related underlying reserves, was $0.98, $1.06, $0.99 and $1.06 per mcfe during the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively. The per unit decrease from June 30, 2018 to June 30, 2019 was the result of a 77% increase in total proved reserves, which was offset by a 62% 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, $1.0 million, $1.5 million and $1.9 million for the three months ended June 30, 2019 and 2018 and the six months ended June 30, 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 $24.9 million, $20.9 million, $46.0 million and $40.5 million for the three months ended June 30, 2019 and 2018 and the six months ended June 30, 2019 and 2018, respectively, detailed as follows along with our weighted average debt outstanding:

($ in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Interest expense on Credit Facility	$ 15,062	$ 7,363	$ 31,285	$ 13,103
Interest expense on 2022 Notes	24,375	37,507	48,750	75,012
Interest expense on 2026 Notes	10,500	—	21,000	—
Interest expense on Convertible Notes	1,218	1,056	2,418	2,044
Other	842	657	1,607	1,499
Amortization of debt discount and issuance costs	5,676	5,510	11,111	10,111
Capitalized interest	(32,805)	(31,220)	(70,160)	(61,319)
Total Interest Expense, net	$ 24,868	$ 20,873	$ 46,011	$ 40,450
Weighted Average Debt Outstanding:				
Credit Facility	$ 1,075,495	$ 192,033	$ 1,042,519	$ 98,674
2022 Notes	975,000	1,500,000	975,000	1,500,000
2026 Notes	600,000	—	600,000	—
Convertible Notes	74,902	70,431	74,133	69,817
Weighted Average Debt Outstanding	$ 2,725,397	$ 1,762,464	$ 2,691,652	$ 1,668,491

The increase in interest expense for the three and six months ended June 30, 2019 compared to the same periods in 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 87% of our June 30, 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 six months ended June 30, 2019 and 2018, the average daily Henry Hub spot market price of natural gas was $2.70 per mmbtu and $2.92 per mmbtu, respectively, and the average daily West Texas Intermediate oil price was $57.45 per bbl and $65.46 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 June 30, 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 relative to NYMEX: 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 June 30, 2019, we had a net asset commodity derivative position of $248.4 million. The following table sets forth the volumes per day associated with our outstanding natural gas derivative instruments as of June 30, 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:						$ 284,562
Remaining in 2019	1,784,000	$ 2.84				
2020	1,430,000	$ 2.74				
2021	450,000	$ 2.73				
2022	50,000	$ 2.82				
2023	100,000	$ 2.70				
Collars:						10,125
Remaining in 2019	7,500		$ 3.40	$ 2.75		
2020	140,000		$ 3.09	$ 2.59		
2021	10,000		$ 2.91	$ 2.50		
Three-way collars:						2,950
2021	270,000		$ 2.91	$ 2.50	$ 2.00	
2022	160,000		$ 3.00	$ 2.50	$ 2.01	
Call options:						(50,129)
Remaining in 2019	140,000		$ 3.00			
2020	250,000		$ 3.00			
2021	335,000		$ 3.02			
2022	260,000		$ 3.04			
2023	170,000		$ 3.00			
Basis swaps:						(15,363)
Remaining in 2019	691,000	$ (0.31)				
2020	747,000	$ (0.36)				
2021	100,000	$ (0.52)				
Total Estimated Fair Value						$ 232,145

The following table sets forth the volumes per day associated with our outstanding oil derivative instruments as of June 30, 2019, the contracted weighted average oil prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Fixed Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Oil:						
Swaps:						$ 1,821
Remaining in 2019	7,000	$ 56.92				
2020	4,500	$ 56.09				
2021	2,000	$ 58.42				
Three-way collars:						314
2021	1,000		$ 65.30	$ 52.50	$ 42.50	
Call options:						(4,149)
Remaining in 2019	2,000		$ 70.00			
2020	4,750		$ 70.00			
2021	3,500		$ 70.00			
Total Estimated Fair Value						$ (2,014)

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of June 30, 2019, the contracted weighted average NGL prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
NGL:				
Swaps - Propane:				$ 17,337
Remaining in 2019	4,500	$ 36.47		
2020	3,000	$ 30.07		
Call options - Propane:				(614)
Remaining in 2019	3,150		$ 33.60	
2020	3,150		$ 33.60	
Swaps - Ethane:				1,548
Remaining in 2019	1,000	$ 17.01		
Total Estimated Fair Value				$ 18,271

As of June 30, 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 $83.1 million, respectively. As of June 30, 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 $4.5 million, respectively. As of June 30, 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 $2.2 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 associated with 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 customer would materially impact our operating results, as natural gas, oil and NGL are fungible products with well-established markets and we transact with numerous customers 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. 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, and the weighted average interest rate as of June 30, 2019 was 4.42%. The LIBOR component of our interest related to borrowings under the Credit Facility exposes us to interest rate risk. A 1.00% increase in the LIBOR for the three and six months ended June 30, 2019 would have resulted in estimated increases of $2.6 million and $5.1 million, respectively, in interest expense on borrowings under the Credit Facility. As of June 30, 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 June 30, 2019.

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 six months ended June 30, 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.