UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2017

OR

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

For the transition period from ____________ to ____________

Commission file number 001-37907

EXTRACTION OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

DELAWARE	**46-1473923**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
370 17th Street, Suite 5300 **Denver, Colorado**	**80202**
(Address of principal executive offices)	(Zip Code)

(720) 557-8300
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ☐

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

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

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

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

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

The total number of shares of common stock, par value $0.01 per share, outstanding as of August 7, 2017 was 171,669,220.

EXTRACTION OIL & GAS, INC.
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GLOSSARY OF OIL AND GAS TERMS

Unless indicated otherwise or the context otherwise requires, references in this Quarterly Report on Form 10-Q ("Quarterly Report") to the "Company," "Extraction," "us," "we," "our," or "ours" or like terms refer to Extraction Oil & Gas, Inc. following the completion of our initial public offering on October 17, 2016, as described in our Annual Report on Form 10-K ("Annual Report"). When used in the historical context, the "Company," "Holdings," "us," "we," "our" and "ours" or like terms refer to Extraction Oil & Gas Holdings, LLC and its subsidiaries. Holdings is our accounting predecessor, for which we present the consolidated financial statements for the three and six months ended June 30, 2016 in this Quarterly Report.

The terms defined in this section are used throughout this Quarterly Report:

"Bbl" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"Bbl/d" means Bbl per day.

"Btu" means on British thermal unit – a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"BOE" means barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"BOE/d" means BOE per day.

"CIG" means Colorado Interstate Gas.

"Completion" means the installation of permanent equipment for the production of oil or natural gas.

"Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

"Fracturing" or "hydraulic fracturing" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability and porosity.

"Gas" or *"Natural gas"* means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

"Gross Acres" or *"Gross Wells"* means the total acres or wells, as the case may be, in which we have a working interest.

"Henry Hub" means Henry Hub index. Natural gas distribution point where prices are set for natural gas futures contracts traded on the NYMEX.

"Horizontal drilling" or *"horizontal well"* means a wellbore that is drilled laterally.

"Leases" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

"MBbl" One thousand barrels of oil, condensate or NGL.

"MBoe" One thousand barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"Mcf" is an abbreviation for "1,000 cubic feet," which is a unit of measurement of volume for natural gas.

"MMBtu" One million Btus.

"MMcf" is an abbreviation for "1,000,000 cubic feet," which is a unit of measurement of volume for natural gas.

"Net Acres" or *"Net Wells"* is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"NGL" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

“Overriding royalty” means an interest in the gross revenues or production over and above the landowner’s royalty carved out of the working interest and also unencumbered with any expenses of operation, development or maintenance.

"Proved reserves" means those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

“Reasonable certainty” means a high degree of confidence that the reserves quantities will be recovered, when a deterministic method is used. A high degree of confidence exists if the reserves quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery (“EUR”) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

"Reservoir" means a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"Royalty" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

“SEC” means the Securities and Exchange Commission.

“Undeveloped leasehold acreage” means the leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains estimated net proved reserves.

“Wattenberg Field” means the Greater Wattenberg Area within the Denver-Julesburg Basin of Colorado as defined by the Colorado Oil and Gas Conservation Commission, which are the lands from and including Townships 2 South to 7 North and Ranges 61 West to 69 West, Six Principal Median.

"Working interest" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

"WTI" means the price of West Texas Intermediate oil on the NYMEX.

PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)
(Unaudited)

	June 30, 2017	December 31, 2016
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 88,689	$ 588,736
Accounts receivable		
Trade	25,332	23,154
Oil, natural gas and NGL sales	45,043	34,066
Inventory and prepaid expenses	10,824	7,722
Commodity derivative asset	22,308	—
Total Current Assets	192,196	653,678
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	2,346,053	1,851,052
Unproved oil and gas properties	501,090	452,577
Wells in progress	167,086	98,747
Less: accumulated depletion, depreciation and amortization	(518,185)	(402,912)
Net oil and gas properties	2,496,044	1,999,464
Other property and equipment, net of accumulated depreciation	26,345	32,721
Net Property and Equipment	2,522,389	2,032,185
Non-Current Assets:		
Cash held in escrow	8,400	42,200
Commodity derivative asset	8,443	—
Goodwill and other intangible assets, net of accumulated amortization	54,793	54,489
Other non-current assets	10,306	2,224
Total Non-Current Assets	81,942	98,913
Total Assets	$ 2,796,527	$ 2,784,776
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 154,065	$ 131,134
Revenue payable	36,498	35,162
Production taxes payable	38,925	27,327
Commodity derivative liability	10	56,003
Accrued interest payable	19,977	19,621
Asset retirement obligations	4,946	5,300
Total Current Liabilities	254,421	274,547
Non-Current Liabilities:		
2021 Senior Notes, net of unamortized debt issuance costs	539,238	538,141
Production taxes payable	21,140	35,838
Commodity derivative liability	—	6,738
Other non-current liabilities	3,307	3,466
Asset retirement obligations	54,801	50,808
Deferred tax liability	115,576	106,026
Total Non-Current Liabilities	734,062	741,017
Total Liabilities	988,483	1,015,564
Commitments and Contingencies—Note 11		
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized; 185,280 issued and outstanding	155,690	153,139
Stockholders' Equity:		
Common stock, $0.01 par value; 900,000,000 shares authorized; 171,834,605 issued and outstanding	1,718	1,718
Additional paid-in capital	2,087,915	2,067,590
Accumulated deficit	(437,279)	(453,235)
Total Stockholders' Equity	1,652,354	1,616,073
Total Liabilities and Stockholders' Equity	$ 2,796,527	$ 2,784,776

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Revenues:				
Oil sales	$ 85,394	$ 50,047	$ 137,522	$ 84,135
Natural gas sales	18,526	8,331	38,423	14,937
NGL sales	15,846	6,986	33,460	11,424
Total Revenues	119,766	65,364	209,405	110,496
Operating Expenses:				
Lease operating expenses	24,165	13,369	46,488	25,339
Production taxes	10,511	6,258	16,964	10,748
Exploration expenses	6,438	5,921	17,250	8,752
Depletion, depreciation, amortization and accretion	68,610	49,330	119,263	94,638
Impairment of long lived assets	—	22,438	675	22,884
Other operating expenses	—	—	451	891
Acquisition transaction expenses	—	—	68	—
General and administrative expenses	23,487	7,974	49,175	15,114
Total Operating Expenses	133,211	105,290	250,334	178,366
Operating Loss	(13,445)	(39,926)	(40,929)	(67,870)
Other Income (Expense):				
Commodity derivatives gain (loss)	33,876	(74,614)	84,298	(78,650)
Interest expense	(9,021)	(13,130)	(18,681)	(26,698)
Other income	250	56	818	84
Total Other Income (Expense)	25,105	(87,688)	66,435	(105,264)
Income (Loss) Before Income Taxes	11,660	(127,614)	25,506	(173,134)
Income tax expense	4,420	—	9,550	—
Net Income (Loss)	$ 7,240	$ (127,614)	$ 15,956	$ (173,134)
Earnings Per Common Share (Note 10)				
Basic and diluted	$ 0.02		$ 0.05	
Weighted Average Common Shares Outstanding				
Basic and diluted	171,835		171,835	

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBERS' AND STOCKHOLDERS' EQUITY
(In thousands)
(Unaudited)

	Members' Units			Common Stock				
	Tranche A Units	Preferred Tranche C Units	Amount	Shares	Amount	Additional Paid in Capital	Retained Earnings (Deficit)	Total Equity
Balance at January 1, 2016	231,101	78,444	$ 751,466	—	$ —	$ —	$ 2,766	$ 754,232
Units issued	—	35,806	116,370	—	—	—	—	116,370
Units repurchased	(131)	(82)	(658)	—	—	—	—	(658)
Unit issuance costs	—	—	(1,022)	—	—	—	—	(1,022)
Restricted stock units issued	1,547	—	—	—	—	—	—	—
Unit-based compensation	—	—	2,606	—	—	—	—	2,606
Net loss	—	—	—	—	—	—	(173,134)	(173,134)
Balance at June 30, 2016	232,517	114,168	$ 868,762	—	$ —	$ —	$ (170,368)	$ 698,394
Balance at January 1, 2017	—	—	$ —	171,835	$ 1,718	$ 2,067,590	$ (453,235)	$ 1,616,073
Common stock issuance costs	—	—	—	—	—	(202)	—	(202)
Stock-based compensation	—	—	—	—	—	28,597	—	28,597
Series A Preferred Stock dividends	—	—	—	—	—	(5,443)	—	(5,443)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	—	(2,627)	—	(2,627)
Net income	—	—	—	—	—	—	15,956	15,956
Balance at June 30, 2017	—	—	$ —	171,835	$ 1,718	$ 2,087,915	$ (437,279)	$ 1,652,354

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	For the Six Months Ended June 30, 2017	2016
Cash flows from operating activities:		
Net income (loss)	$ 15,956	$ (173,134)
Reconciliation of net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	119,263	94,638
Abandonment and impairment of unproved properties	4,560	2,862
Impairment of long lived assets	675	22,884
Loss on sale of property and equipment	451	—
Amortization of debt issuance costs and debt discount	1,712	2,424
Deferred rent	(156)	386
Commodity derivatives (gain) loss	(84,298)	78,650
Settlements on commodity derivatives	(13,240)	42,184
Premiums paid on commodity derivatives	—	(611)
Deferred income tax expense	9,550	—
Unit and stock-based compensation	28,597	2,606
Equity in earnings of unconsolidated affiliate	10	—
Changes in current assets and liabilities:		
Accounts receivable—trade	(618)	(1,755)
Accounts receivable—oil, natural gas and NGL sales	(10,977)	(5,632)
Inventory and prepaid expenses	(103)	(253)
Accounts payable and accrued liabilities	(3,186)	(16,667)
Revenue payable	1,336	(3,423)
Production taxes payable	(3,109)	(3,531)
Accrued interest payable	356	(304)
Asset retirement expenditures	(952)	(146)
Net cash provided by operating activities	65,827	41,178
Cash flows from investing activities:		
Oil and gas property additions	(572,105)	(159,646)
Acquired oil and gas properties	(17,225)	—
Sale of property and equipment	2,000	2,148
Other property and equipment additions	(5,790)	(2,582)
Cash held in escrow	33,800	—
Net cash used in investing activities	(559,320)	(160,080)
Cash flows from financing activities:		
Borrowings under credit facility	—	10,000
Proceeds from the issuance of units	—	116,370
Repurchase of units	—	(658)
Dividends on Series A Preferred Stock	(4,958)	—
Debt issuance costs	(109)	—
Equity issuance costs	(1,487)	(246)
Net cash provided by (used in) financing activities	(6,554)	125,466
Increase (decrease) in cash and cash equivalents	(500,047)	6,564
Cash and cash equivalents at beginning of period	588,736	97,106
Cash and cash equivalents at end of the period	$ 88,689	$ 103,670
Supplemental cash flow information:		
Property and equipment included in accounts payable and accrued liabilities	$ 134,483	$ 49,674
Cash paid for interest	$ 22,256	$ 26,947
Accretion of beneficial conversion feature of Series A Preferred Stock	$ 2,627	$ —
Non-cash contribution to unconsolidated affiliate	$ 8,191	$ —
Increase in dividends payable	$ 485	$ —

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business and Organization

Extraction Oil & Gas, Inc. (the “Company” or “Extraction”) is an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the “DJ Basin”) of Colorado. The Company and its subsidiaries are focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, as well as the design and support of midstream assets to gather and process crude oil and gas production focused in the DJ Basin of Colorado. Extraction is a public company listed for trading on the NASDAQ Global Select Market under the symbol “XOG”.

The condensed consolidated financial statements for the three and six months ended June 30, 2016 are based on the financial statements of the Company’s accounting predecessor, Extraction Oil & Gas Holdings, LLC, prior to the corporate reorganization (the “Corporate Reorganization”), pursuant to which, in connection with the initial public offering of the Company, (i) on October 11, 2016, a former subsidiary of Extraction Oil & Gas Holdings, LLC, Extraction Oil & Gas, LLC, converted into the Company, and (ii) on October 17, 2016, Holdings merged with and into the Company with the Company as the surviving entity. For further information on the Corporate Reorganization please refer to the Company’s Annual Report on Form 10-K for the year ended December 31, 2016 (“Annual Report”).

Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements

Basis of Presentation

The unaudited condensed consolidated financial statements include the accounts of the Company, including its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States (“GAAP”) and the SEC rules and regulation for interim financial reporting. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the consolidated financial information, have been included. However, operating results for the period presented are not necessarily indicative of the results that may be expected for a full year. Interim condensed consolidated financial statements and the year-end balance sheet do not include all of the information and notes required by GAAP for audited annual consolidated financial statements. These unaudited financial statements should be read in conjunction with the Company’s audited financial statements and notes included in the Company’s Annual Report.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 2 to the Company’s consolidated financial statements in its Annual Report, and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Company’s Annual Report.

Recent Accounting Pronouncements

In May 2017, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2017-09, which provides clarification and reduces both (1) diversity in practice and (2) cost and complexity when applying the guidance in Topic 718 Compensation - Stock Compensation, to a change to the terms or conditions of a share-based payment award. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that reporting period. Early adoption is permitted for fiscal years beginning after December 15, 2016, including the interim reporting periods within that fiscal year. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In February 2017, the FASB issued ASU No. 2017-05, which provides clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that reporting period. Early adoption is permitted for fiscal years beginning after December 15, 2016, including the interim reporting periods within that fiscal year. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-04, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit’s goodwill with the carrying amount. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, which clarifies the definition of a business when evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted for transactions for which the acquisition date occurs before the issuance date or effective date of the amendments, only when the transaction has not been reported in the financial statements that have been issued. The Company is currently evaluating this new standard and believes it could have a material impact to its financial statements and related disclosures.

In November 2016, the FASB issued ASU No. 2016-18, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment will be effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In August 2016, the FASB issued ASU No. 2016-15, which addresses eight specific cash flow issues, including presentation of debt prepayments or debt extinguishment costs, with the objective of reducing the existing diversity in practice. In addition, in November 2016, the FASB issued ASU 2016-18, which requires that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including an adoption in an interim period, with a required retrospective application to each period presented. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-06, which clarifies the requirements to assess whether an embedded put or call option is clearly and closely related to the debt host, solely in accordance with the four step decision sequence in FASB ASC Topic 815, Derivatives and Hedging, as amended by ASU 2016-06. This standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 and should be applied using a modified retrospective approach. Early adoption is permitted. The Company is currently evaluating the impact of adopting this new standard, however the standard is not expected to have a significant effect on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, which requires lessee recognition on the balance sheet of a right of use asset and a lease liability, initially measured at the present value of the lease payments. It further requires recognition in the income statement of a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight line basis. Finally, it requires classification of all cash payments within operating activities in the statements of cash flows. It is effective for fiscal years commencing after December 15, 2018 and early adoption is permitted. The Company is currently evaluating the impact this new standard will have on its financial statements and related disclosures. As part of the Company’s assessment work to-date, the Company formed an implementation work team, completed training of the new ASU's leasing guidance, and is developing a strategy for implementation.

In May 2014, the FASB issued ASU No. 2014-09, which establishes a comprehensive new revenue recognition model designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The ASU allows for the use of either the full or modified retrospective transition method. In August 2015, the FASB issued ASU No. 2015-14, which deferred ASU No. 2014-09 for one year, and is effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of reporting periods beginning after December 15, 2016. The FASB subsequent issued ASU 2016-08, ASU 2016-10, ASU 2016-11 and ASU 2016-12, and 2016-20, which provided additional implementation guidance. The Company is in the process of completing its initial review of contracts in each of its revenue streams and is developing accounting policies to address the provisions of this ASU. While the Company does not currently expect operating income (loss) to be materially impacted, the Company is currently analyzing whether total revenues and total expenses may change as a result of certain percentage of proceeds contracts. The Company will continue to evaluate the impact of this and other provisions of the ASU on its accounting policies, internal controls, and consolidated financial statements and related disclosures and has not finalized any estimates of the potential impacts. The Company will adopt this new standard on January 1, 2018, using the modified retrospective method with a cumulative adjustment to retained earnings.

Other than as disclosed above or in the Company’s Annual Report, there are no other accounting standards applicable to the Company that would have a material effect on the Company’s financial statements and related disclosures that have been issued but not yet adopted by the Company through the date of this filing.

Note 3—Acquisitions

July 2017 Acquisition

On July 7, 2017, the Company acquired an unaffiliated oil and gas company’s interests in approximately 12,500 net acres of leasehold, and related producing and non-producing properties located in the DJ Basin of Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "July 2017 Acquisition"). Upon closing the seller received total consideration of $84.0 million in cash, subject to customary purchase price adjustments. The effective date for the July 2017 Acquisition is July 1, 2017. The acquisition provides new development opportunities in the DJ Basin. An $8.4 million deposit was made in March 2017 in conjunction with the July 2017 Acquisition, which has been reflected in the June 30, 2017 consolidated balance sheet within the cash held in escrow line item and was credited towards the purchase price at closing.

June 2017 Acquisition

On June 8, 2017, the Company acquired an unaffiliated oil and gas company’s interests in approximately 160 net acres of leasehold and related producing properties located in Weld County, Colorado (the “June 2017 Acquisition”). The Company paid approximately $13.4 million in cash consideration in connection with the closing of the June 2017 Acquisition. The effective date for the acquisition was January 1, 2017, with purchase price adjustments calculated as of the closing date of June 8, 2016. The acquisition increased the Company's interest in existing operated wells. The acquired producing properties contributed de minimis revenue and earnings for three and six months ended June 30, 2017. No transaction costs related to the acquisition were incurred for the three and six months ended June 30, 2017 and 2016.

The June 2017 Acquisition was accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of June 8, 2017. The Company has not completed the transaction's post-closing settlement. As the post-close has not occurred, management has not had the opportunity to complete its assessment of the fair values of assets acquired and liabilities assumed. Accordingly, the below allocation will change as additional information becomes available and is assessed by the Company, and the impact of such changes may be material. The following table summarizes the preliminary purchase price and the preliminary estimated value of assets acquired and liabilities assumed (in thousands):

Preliminary Purchase Price		**June 8, 2017**
Consideration given		
Cash	$	13,395
Total consideration given	$	13,395
Preliminary Allocation of Purchase Price		
Proved oil and gas properties	$	13,495
Total fair value of oil and gas properties acquired	$	13,495
Asset retirement obligations		(100)
Fair value of net assets acquired	$	13,395

November 2016 Acquisition

On November 22, 2016, the Company acquired an unaffiliated oil and gas company's interest in approximately 9,200 net acres of leaseholds located in the DJ Basin for approximately $120.0 million, including customary closing adjustments (the "November 2016 Acquisition"). The Company also made a $41.1 million deposit in November 2016 in conjunction with November 2016 Acquisition, which has been reflected in the December 31, 2016 consolidated balance sheet within the cash held in escrow line item. The deposit was made for two additional closings of leaseholds located in the DJ Basin. The first closing occurred in January 2017 and added approximately 5,300 net acres. The second closing occurred in July 2017 and added approximately 640 net acres.

October 2016 Acquisition

On October 3, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 6,400 net acres of leasehold, and related producing and non-producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "October 2016 Acquisition" or the "Bayswater Acquisition"). The seller received aggregate consideration of approximately $405.3 million in cash. The effective date for the acquisition was July 1, 2016, with purchase price adjustments calculated as of the closing date on October 3, 2016. The acquisition provides new development opportunities in the DJ Basin as well as increases the Company's existing working interest, as the majority of the locations are located on acreage in which the Company already owns a majority working interest and operates. The Company incurred $2.6 million of transaction costs related to the acquisition. These transaction costs were recorded in the consolidated statements of operations within the acquisition transaction expenses line item in the third and fourth quarter of 2016. No transaction costs related to the acquisition were incurred for the three and six months ended June 30, 2017 and 2016.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of October 3, 2016. In February 2017, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price		**October 3, 2016**
Consideration given		
Cash	$	405,335
Total consideration given	$	405,335
Allocation of Purchase Price		
Proved oil and gas properties	$	252,522
Unproved oil and gas properties		109,800
Total fair value of oil and gas properties acquired	$	362,322
Goodwill (1)	$	54,220
Working capital		(7,185)
Asset retirement obligations		(4,022)
Fair value of net assets acquired	$	405,335
Working capital acquired was estimated as follows:		
Accounts receivable	$	955
Revenue payable		(3,012)
Production taxes payable		(4,244)
Accrued liabilities		(884)
Total working capital	$	(7,185)

(1) Goodwill is primarily attributable to a decrease in commodity prices from the time the acquisition was negotiated to commodity prices on October 3, 2016 and the operational and financial synergies expected to be realized from the acquisition. Goodwill recognized as a result of the Bayswater Acquisition is not deductible for income tax purposes.

August 2016 Acquisition

On August 23, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 1,400 net acres of leasehold located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way and other assets (the "August 2016 Acquisition"). The seller received aggregate consideration of approximately $17.5 million in cash. The effective date for the acquisition was August 31, 2016, with purchase price adjustments calculated as of the closing date of August 23, 2016. The acquisition provided new development opportunities in the DJ Basin as well as additions adjacent to the Company's core project area. The Company incurred $0.1 million of transaction costs related to the acquisition. These transaction costs were recorded in the consolidated statements of operations within the acquisition transaction expenses line item in the third quarter of 2016. No transaction costs related to the acquisition were incurred for the three and six months ended June 30, 2017 and 2016.

The acquisition was accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of August 23, 2016. In March 2017, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price		**August 23, 2016**
Consideration given		
Cash	$	17,504
Total consideration given	$	17,504
Allocation of Purchase Price		
Proved oil and gas properties	$	12,362
Unproved oil and gas properties		8,566
Total fair value of oil and gas properties acquired	$	20,928
Working capital	$	(9)
Asset retirement obligations		(3,415)
Fair value of net assets acquired	$	17,504
Working capital acquired was estimated as follows:		
Production taxes payable		(9)
Total working capital	$	(9)

Pro Forma Financial Information (Unaudited)

For the three and six months ended June 30, 2016, the following pro forma financial information represents the combined results for the Company and the properties acquired in October 2016 as if the acquisition and related financing had occurred on January 1, 2016. For purposes of the pro forma financial information, it was assumed that the October 2016 Acquisition was funded through the issuance of $260.3 million in convertible preferred securities and borrowings under the revolving credit facility. The pro forma information includes the effects of adjustments for depletion, depreciation, amortization and accretion expense of $8.7 million and $14.1 million for the three and six months ended June 30, 2016, respectively. No pro forma adjustments were made for the effect of income taxes for the three and six months ended June 30, 2016 as the acquisitions occurred before the Corporate Reorganization. The October 2016 Acquisition was included in the historical results of the Company for the three and six months ended June 30, 2017, therefore this acquisition has no impact on the pro forma financial information for the three and six months ended June 30, 2017. Additionally, the pro forma financial information excludes the effects the August 2016 Acquisition as these pro forma adjustments were de minimis. For the three and six months ended June 30, 2017, the following pro forma financial information represents the combined results for the Company and the properties acquired in the June 2017 Acquisition as if the acquisition had occurred on January 1, 2016. The June 2017 Acquisition has no impact on the historical results of the Company for the three and six months ended June 30, 2016. For purposes of pro forma financial information, it was assumed that the June 2017 Acquisition was funded through cash. The pro forma financial information includes the effects of adjustments for depletion, depreciation, amortization and accretion expense of $1.6 million for the three and six months ended June 30, 2017. The pro forma financial information includes the effects of adjustments for income tax expense of $0.6 million for the three and six months ended June 30, 2017.

The following pro forma results (in thousands) do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Company to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the period, nor are they necessarily indicative of future results. Net earnings (loss) per common share is not applicable for the period prior to the Corporate Reorganization.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Revenues	$ 121,930	$ 86,329	$ 211,569	$ 138,189
Operating expenses	$ 135,090	$ 116,946	$ 252,213	$ 197,911
Net income (loss)	$ 7,417	$ (119,313)	$ 16,133	$ (167,002)
Earnings per common share, basic and diluted	$ 0.02		$ 0.05	

Note 4—Long-Term Debt

As of the dates indicated, the Company’s long-term debt consisted of the following (in thousands):

	June 30, 2017	December 31, 2016
Credit facility due November 29, 2018	$ —	$ —
2021 Senior Notes due July 15, 2021	550,000	550,000
Unamortized debt issuance costs on 2021 Senior Notes	(10,762)	(11,859)
Total long-term debt	539,238	538,141
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 539,238	$ 538,141

Credit Facility

The Company has commitments of $1.0 billion on its credit facility with a syndicate of banks, which is subject to a borrowing base. As of June 30, 2017, the credit facility was subject to a borrowing base of $475.0 million. The credit facility matures on November 29, 2018. As of June 30, 2017 and December 31, 2016, the Company had no outstanding borrowings. As of June 30, 2017 and December 31, 2016, the Company had standby letters of credit of $20.6 million and $0.6 million, respectively. At June 30, 2017, the undrawn balance under the credit facility was $475.0 million. As discussed below, in connection with the closing of the 2024 Senior Notes Offering, as defined below, the Company's borrowing base was automatically reduced to $375.0 million. As of the date of this filing, the Company had no borrowings outstanding under the credit facility.

Redetermination of the borrowing base occurs semiannually on May 1 and November 1. Additionally, the Company and the administrative agent under the credit facility may each elect a redetermination of the borrowing base between any two scheduled redeterminations. In addition, the Company has exercised its right for a redetermination of the borrowing base on or about August 1, 2017.

Interest on the credit facility is payable at one of the following two variable rates as selected by the Company: a base rate based on the Prime Rate or the Eurodollar rate, based on LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the pricing grid below. Additionally, the credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. The grid below shows the Base Rate Margin and Eurodollar Margin depending on the applicable Borrowing Base Utilization Percentage (as defined in the credit facility) as of the date of this filing:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	Utilization	LIBOR Margin	Base Rate Margin	Commitment Fee
Level 1	< 25%	2.00%	1.00%	0.375%
Level 2	≥ 25% < 50%	2.25%	1.25%	0.375%
Level 3	≥ 50% < 75%	2.50%	1.50%	0.500%
Level 4	≥ 75% < 90%	2.75%	1.75%	0.500%
Level 5	≥ 90%	3.00%	2.00%	0.500%

The credit facility contains representations, warranties, covenants, conditions and defaults customary for transactions of this type, including but not limited to: (i) limitations on liens and incurrence of debt covenants; (ii) limitations on dividends, distributions, redemptions and restricted payments covenants; (iii) limitations on investments, loans and advances covenants; (iv) limitations on the sale of property, mergers, consolidations and other similar transactions covenants; and (v) holding cash balances in excess of certain thresholds while carrying a balance on the credit facility. Additionally, the credit facility limits the Company entering into hedges in excess of 85% of its anticipated production volumes.

The credit facility also contains financial covenants requiring the Company to comply with a current ratio of its consolidated current assets (includes availability under the revolving credit facility and unrestricted cash and excludes derivative assets) to its consolidated current liabilities (excludes obligations under the revolving credit facility, senior notes and certain derivative liabilities), of not less than 1.0 to 1.0 and to maintain, on the last day of each quarter, a ratio of consolidated debt less cash balances in excess of certain thresholds to its consolidated EBITDAX (EBITDAX is defined as net income adjusted for certain cash and non-cash items including depletion, depreciation, amortization and accretion, exploration expense, gains/losses on derivative instruments, amortization of certain debt issuance costs, non-cash compensation expense, interest expense and prepayment premiums on extinguishment of debt) for the four fiscal quarter period most recently ended, of not greater than 4.0:1.0. For the quarters ending between and including December 31, 2016 through December 31, 2017, annualized EBITDAX will be based on the last six months' consolidated EBITDAX multiplied by 2, and for the quarter ending March 31, 2018, annualized EBITDAX will be based on the last nine months' consolidated EBITDAX multiplied by 4/3. For the quarters ending on or after June 30, 2018, annualized EBITDAX will be based on the last twelve months' consolidated EBITDAX. The Company was in compliance with all financial covenants under the credit facility as of June 30, 2017 and through the filing of this report.

Any borrowings under the credit facility are collateralized by substantially all of the assets of the Company and its subsidiaries, including oil and gas properties, personal property and the equity interests of the subsidiaries of the Company. The Company has entered into oil and natural gas hedging transactions with several counterparties that are also lenders under the credit facility. The Company's obligations under these hedging contracts are secured by the collateral securing the credit facility.

2021 Senior Notes

In July 2016, the Company issued at par $550.0 million principal amount of 7.875% Senior Notes due July 15, 2021 (the "2021 Senior Notes" and the offering, the "2021 Senior Notes Offering"). The 2021 Senior Notes bear an annual interest rate of 7.875%. The interest on the 2021 Senior Notes is payable on January 15 and July 15 of each year commencing on January 15, 2017. The Company received net proceeds of approximately $537.2 million after deducting discounts and fees.

The 2021 Senior Notes are the Company's senior unsecured obligations and rank equally in right of payment with all of its other senior indebtedness and senior to any of its subordinated indebtedness. The 2021 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of the Company's current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of the 2021 Senior Notes) that guarantees its indebtedness under a credit facility (the "Guarantors"). The notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under its revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the notes.

The 2021 Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company’s or any of its Guarantors’ equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The indenture governing the 2021 Senior Notes (the “2021 Senior Notes Indenture”) also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2021 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2021 Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2021 Senior Notes may declare all outstanding 2021 Senior Notes to be due and payable immediately. The Company was in compliance with all financial covenants under the 2021 Senior Notes Indenture as of June 30, 2017, and through the filing of this report.

2024 Senior Notes

In August 2017, the Company issued at par $400.0 million principal amount of 7.375% Senior Notes due May 15, 2024 (the “2024 Senior Notes” and the offering, the “2024 Senior Notes Offering”). The 2024 Senior Notes bear an annual interest rate of 7.375%. The interest on the 2024 Senior Notes is payable on May 15 and November 15 of each year commencing on November 15, 2017. The Company received net proceeds of approximately $392.8 million after deducting discounts and fees.

The Company's 2024 Senior Notes are its senior unsecured obligations and rank equally in right of payment with all of its other senior indebtedness and senior to any of its subordinated indebtedness. The Company's 2024 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of its current subsidiaries and by certain future restricted subsidiaries that guarantees its indebtedness under a credit facility (the “2024 Senior Note Guarantors”). The notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under its revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any of its future subsidiaries that do not guarantee the notes.

The 2024 Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company’s or any of its Guarantors’ equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The indenture governing the 2024 Senior Notes (the “2024 Senior Notes Indenture”) also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2024 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2024 Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2024 Senior Notes may declare all outstanding 2024 Senior Notes to be due and payable immediately. The Company was in compliance with all financial covenants under the 2024 Senior Notes Indenture through the filing of this report.

Debt Issuance Costs

As of June 30, 2017, the Company had debt issuance costs, net of accumulated amortization, of $1.8 million related to its credit facility which has been reflected on the Company’s balance sheet within the line item other non-current assets. As of June 30, 2017, the Company had debt issuance costs, net of accumulated amortization, of $10.8 million related to its 2021 Senior Notes which has been reflected on the Company's balance sheet within the line item 2021 Senior Notes, net of unamortized debt issuance costs. Debt issuance costs include origination, legal, engineering and other fees incurred in connection with the Company’s credit facility and 2021 Senior Notes. For the three and six months ended June 30, 2017, the

Company recorded amortization expense related to debt issuance costs of $0.9 million and $1.7 million, respectively as compared to $0.9 million and $1.8 million for the three and six months ended June 30, 2016, respectively.

Debt Discount Costs on Second Lien Notes

For the three and six months ended June 30, 2016, the Company recorded amortization expense related to the debt discount on its Second Lien Notes of $0.3 million and $0.6 million, respectively. The Company recorded no amortization expense related to the debt discount on its Second Lien Notes for the three and six months ended June 30, 2017. For additional information regarding debt discount costs on Second Lien Notes, see the Company's Annual Report.

Interest Incurred on Long-Term Debt

For the three and six months ended June 30, 2017, the Company incurred interest expense on long-term debt of $11.3 million and $22.6 million, respectively, as compared to $13.3 million and $26.6 million for the three and six months ended June 30, 2016, respectively. For the three and six months ended June 30, 2017, the Company capitalized interest expense on long term debt of $3.2 million and $5.6 million, respectively, as compared to $1.4 million and $2.4 million for the three and six months ended June 30, 2016, respectively, which has been reflected in the Company's financial statements.

Note 5—Commodity Derivative Instruments

The Company has entered into commodity derivative instruments, as described below. The Company has utilized swaps, put options and call options to reduce the effect of price changes on a portion of the Company's future oil and natural gas production.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of the Company's purchased put options have deferred premiums. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

The Company combines swaps, purchased put options, purchased call options, sold put options and sold call options in order to achieve various hedging strategies. Some examples of the Company's hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap.

The objective of the Company's use of commodity derivative instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these commodity derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with six counterparties. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. The derivative contracts may be terminated by a nondefaulting party in the event of default by one of the parties to the agreement. There are no credit risk related contingent features or circumstances in which the features could be triggered in derivative instruments that are in a net liability position at the end of the reporting period.

The Company's commodity derivative contracts as of June 30, 2017 are summarized below:

	2017	2018
NYMEX WTI[1] Crude Swaps:		
Notional volume (Bbl)	—	4,500,000
Weighted average fixed price ($/Bbl)		$ 51.76
NYMEX WTI[1] Crude Sold Calls:		
Notional volume (Bbl)	4,500,000	2,500,000
Weighted average sold call price ($/Bbl)	$ 56.40	$ 60.61
NYMEX WTI[1] Crude Sold Puts:		
Notional volume (Bbl)	4,250,000	6,600,000
Weighted average sold put price ($/Bbl)	$ 38.41	$ 39.64
NYMEX WTI[1] Crude Purchased Puts:		
Notional volume (Bbl)	4,500,000	2,400,000
Weighted average purchased put price ($/Bbl)	$ 47.94	$ 50.50
NYMEX HH[2] Natural Gas Swaps:		
Notional volume (MMBtu)	14,840,000	34,800,000
Weighted average fixed price ($/MMBtu)	$ 3.06	$ 3.11
NYMEX HH[2] Natural Gas Purchased Puts:		
Notional volume (MMBtu)	—	2,400,000
Weighted average purchased put price ($/MMBtu)		$ 3.00
NYMEX HH[2] Natural Gas Sold Calls:		
Notional volume (MMBtu)	—	2,400,000
Weighted average sold call price ($/MMBtu)		$ 3.15
CIG[3] Basis Gas Swaps:		
Notional volume (MMBtu)	8,895,000	6,300,000
Weighted average fixed basis price ($/MMBtu)	$ (0.34)	$ (0.31)

(1) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange
(2) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange
(3) CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) settlement price.

The following tables detail the fair value of the Company's derivative instruments, including the gross amounts and adjustments made to net the derivative instruments for the presentation in the condensed consolidated balance sheets (in thousands):

	As of June 30, 2017				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offsets in the Balance Sheet[1]**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet[2]**	**Net Amounts[3]**
Current assets	$ 38,224	$ (15,916)	$ 22,308	$ —	$ 30,751
Non-current assets	$ 16,228	$ (7,785)	$ 8,443	$ —	$ —
Current liabilities	$ (15,926)	$ 15,916	$ (10)	$ —	$ (10)
Non-current liabilities	$ (7,785)	$ 7,785	$ —	$ —	$ —

	As of December 31, 2016									
Location on Balance Sheet	Gross Amounts of Recognized Assets and Liabilities		Gross Amounts Offsets in the Balance Sheet[1]		Net Amounts of Assets and Liabilities Presented in the Balance Sheet		Gross Amounts not Offset in the Balance Sheet[2]		Net Amounts[3]	
Current assets	$	12,620	$	(12,620)	$	—	$	—	$	—
Non-current assets	$	14,993	$	(14,993)	$	—	$	—	$	—
Current liabilities	$	(68,623)	$	12,620	$	(56,003)	$	—	$	(62,741)
Non-current liabilities	$	(21,731)	$	14,993	$	(6,738)	$	—	$	—

(1) Agreements are in place with all of the Company’s financial trading counterparties that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.
(2) Netting for balance sheet presentation is performed by current and non-current classification. This adjustment represents amounts subject to an enforceable master netting arrangement, which are not netted on the condensed consolidated balance sheets. There are no amounts of related financial collateral received or pledged.
(3) Net amounts are not split by current and non-current. All counterparties in a net asset position are shown in the current asset line item and all counterparties in a net liability position are shown in the current liability line item.

The table below sets forth the commodity derivatives gain (loss) for the three and six months ended June 30, 2017 and 2016 (in thousands). Commodity derivatives gain (loss) is included under the other income (expense) line item in the condensed consolidated statements of operations.

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2017		2016		2017		2016	
Commodity derivatives gain (loss)	$	33,876	$	(74,614)	$	84,298	$	(78,650)

Note 6—Asset Retirement Obligations

The Company follows accounting for asset retirement obligations in accordance with ASC 410, *Asset Retirement and Environmental Obligations*, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The Company’s asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in wells at the end of their productive lives in accordance with applicable local, state and federal laws and applicable lease terms. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company’s credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement costs are depleted with proved oil and gas properties using the unit-of-production method.

The following table summarizes the activities of the Company’s asset retirement obligations for the period indicated (in thousands):

	For the Six Months Ended June 30, 2017		For the Year Ended December 31, 2016	
Balance beginning of period	$	56,108	$	44,367
Liabilities incurred or acquired		1,950		8,945
Liabilities settled		(951)		(1,155)
Revisions in estimated cash flows		—		(1,695)
Accretion expense		2,640		5,646
Balance end of period	$	59,747	$	56,108

Note 7—Fair Value Measurements

ASC 820, *Fair Value Measurement and Disclosure*, establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

- Level 1: Quoted prices are available in active markets for identical assets or liabilities;
- Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability;
- Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between levels during any periods presented below.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2017 and December 31, 2016 by level within the fair value hierarchy (in thousands):

	Fair Value Measurements at June 30, 2017 Using			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial Assets:				
Commodity derivative assets	$ —	$ 30,751	$ —	$ 30,751
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 10	$ —	$ 10

	Fair Value Measurements at December 31, 2016 Using			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial Assets:				
Commodity derivative assets	$ —	$ —	$ —	$ —
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 62,741	$ —	$ 62,741

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above:

Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market based approach that takes into account several factors, including quoted market prices in active markets, implied market volatility factors, quotes from third parties, the credit rating of each counterparty and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. Derivative instruments utilized by the Company consist of swaps, put options and call options. The oil and natural gas derivative markets are highly active. Although the Company's derivative instruments are valued using public indices, the instruments themselves are traded with third party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximated fair value as it bears interest at variable rates over the term of the loan. The fair value of the 2021 Senior Notes was derived from available market data. As such, the Company has classified the 2021 Senior Notes as Level 2. Please refer to *Note 4—Long-Term Debt* for further information. The Company's policy is to recognize transfers between levels at the end of the period. This disclosure (in thousands) does not impact the Company's financial position, results of operations or cash flows.

	At June 30, 2017		At December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
2021 Senior Notes[(1)]	$ 539,238	$ 565,125	$ 538,141	$ 588,500

(1) The carrying amount of the 2021 Senior Notes includes unamortized debt issuance costs of $10.8 million and $11.9 million as of June 30, 2017 and December 31, 2016, respectively.

Non-Recurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property and goodwill. These assets and liabilities are not measured at fair value on a recurring basis, but are subject to fair value adjustments when facts and circumstances arise that indicate a need for remeasurement.

The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on the net discounted future cash flows of producing property. The future cash flows are based on Management's estimates for the future. Unobservable inputs include estimates of oil and gas production, as the case may be, from the Company's reserve reports, commodity prices based on the sales contract terms or forward price curves, operating and development costs and a discount rate based on a market-based weighted average cost of capital (all of which are Level 3 inputs within the fair value hierarchy). No impairment expense was recognized for the three and six months ended June 30, 2017 on proved oil and gas properties. For the three and six months ended June 30, 2016, the Company recognized $22.4 million in impairment expense on its proved oil and gas properties related to impairment of assets in its northern field. The future undiscounted cash flows did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties was impaired at June 30, 2016.

The Company applies the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated value of the net assets acquired in business combinations. The Company tests goodwill for impairment annually on September 30, or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test is performed at the reporting unit level, which represents the Company's oil and gas operations in the DJ Basin. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. The Company utilizes the market approach to determine the fair value of the reporting unit. Any sharp prolonged decreases in the prices of oil and natural gas as well as continued declines in the quoted market price of the Company's common shares could change the estimates of the fair value of the reporting unit and could result in an impairment charge. The Company performed a qualitative assessment as of June 30, 2017, which concluded the fair value of the reporting unit was more-likely-than-not greater than its carrying amount.

The Company's other non-recurring fair value measurements include the purchase price allocations for the fair value of assets and liabilities acquired through business combinations, please refer to *Note 3 — Acquisitions*. The fair value of assets and liabilities acquired through business combinations is calculated using a discounted cash flow approach using level 3 inputs.

Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including risk-adjusted oil and gas reserves, commodity prices, development costs and operating costs, based on market participant assumptions. The fair value of assets or liabilities associated with purchase price allocations is on a non-recurring basis and is not measured in periods after initial recognition.

Note 8—Income Taxes

The Company computes an estimated annual effective rate each quarter based on the current and forecasted operating results. The income tax expense or benefit associated with the interim period is computed using the most recent estimated annual effective rate applied to the year-to-date ordinary income or loss, plus the tax effect of any significant discrete or infrequently occurring times recorded during the interim period. The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgment including, but not limited to, the expected operating income for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent differences and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained and additional information becomes known or as the tax environment changes.

The effective combined U.S. federal and state income tax rate for the six months ended June 30, 2017 was 37.4%. During the six months ended June 30, 2017, the Company recognized income tax expense of $9.6 million. The effective rate for the six months ended June 30, 2017 differs from the statutory U.S. federal income tax rate of 35% primarily due to state income taxes and estimated permanent differences. There were no significant discrete items recorded during the six months ended June 30, 2017. The Company anticipates the potential for increased periodic volatility in future effective tax rates from the impact of stock-based compensation tax deductions as they are treated as discrete tax items. The Company's accounting predecessor was a limited liability company that was not subject to U.S. federal income tax during the first half of 2016.

The Company adopted ASU 2016-09 on January 1, 2017. There was no tax effect upon adoption as the Company did not have an accumulated windfall pool as of December 31, 2016.

Note 9—Unit and Stock-Based Compensation

Extraction Long Term Incentive Plan

In October 2016, the Company's board of directors adopted the Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (the "2016 Plan" or "LTIP"), pursuant to which employees, consultants and directors of the Company and its affiliates performing services for the Company are eligible to receive awards. The 2016 Plan provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, other stock-based awards, substitute awards, annual incentive awards and performance awards intended to align the interests of participants with those of stockholders. The Company reserved 20.2 million shares of common stock for issuance pursuant to awards under the LTIP.

Stock Options

Expense on the stock options are recognized on a straight-line basis over the service period of the award less awards forfeited. The fair value of the stock options were measured at the grant date using the Black-Scholes valuation model. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. Expected volatility is based on the volatility of the historical stock prices of the Company's peer group. The risk-free rates are based on the yields of U.S. Treasury instruments with comparable terms. A dividend yield and forfeiture rate of zero were assumed. Stock options granted under the LTIP vest ratably over three years and are exercisable immediately upon vesting through the tenth anniversary of the grant date. To fulfill options exercised, the Company will issue new shares.

The Company recorded $3.3 million and $6.6 million of stock-based compensation costs related to the stock options for the three and six months ended June 30, 2017, respectively. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. The Company did not record any stock-based compensation expense related to stock options for the three and six months ended June 30, 2016. As of June 30, 2017, there was $29.9 million of unrecognized compensation cost related to the stock options that is expected to be recognized over a weighted average period of 2.3 years.

The following table summarizes the stock option activity from January 1, 2017 through June 30, 2017 and provides information for stock options outstanding at the dates indicated.

	Number of Options	Weighted Average Exercise Price
Non-vested Stock Options at January 1, 2017	4,500,000	$ 19.00
Granted	—	$ —
Forfeited	—	$ —
Vested	—	$ —
Non-vested Stock Options at June 30, 2017	4,500,000	$ 19.00

Restricted Stock Units

Restricted stock units granted under the LTIP ("RSUs") generally vest over either a one or three year service period, with 100% vesting in year one or 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of Extraction's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost. As of January 1, 2017, the Company elected to account for stock-based compensation forfeitures as they occur, as a result of the adoption of ASU 2016-09.

The Company recorded $7.8 million and $15.8 million of stock-based compensation costs related to RSUs for the three and six months ended June 30, 2017, respectively. The Company did not record any stock-based compensation costs related to RSUs for the three and six months ended June 30, 2016. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of June 30, 2017, there was $60.8 million of total unrecognized compensation cost related to the unvested RSUs granted to certain directors, officers and employees that is expected to be recognized over a weighted average period of 2.2 years.

The following table summarizes the RSU activity from January 1, 2017 through June 30, 2017 and provides information for RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested RSUs at January 1, 2017	3,237,500	$ 21.41
Granted	1,227,583	$ 16.70
Forfeited	(393,400)	$ 19.80
Vested	—	$ —
Non-vested RSUs at June 30, 2017	4,071,683	$ 20.15

Incentive Restricted Stock Units

Officers of the Company contributed 2.7 million shares of common stock to Extraction Employee Incentive, LLC ("Employee Incentive"), which is owned solely by certain officers of the Company. Employee Incentive issued restricted stock units ("Incentive RSUs") to certain employees. Incentive RSUs vest over a three-year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of Extraction's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost. As of January 1, 2017, the Company elected to account for stock-based compensation forfeitures as they occur, as a result of the adoption of ASU 2016-09. As the vesting of any Incentive RSUs will be satisfied with shares of common stock that are already issued and outstanding, the Incentive RSUs do not have any impact on the Company's diluted earnings per share calculation.

The Company recorded $1.8 million and $6.2 million of stock-based compensation costs related to Incentive RSUs for the three and six months ended June 30, 2017, respectively. The Company did not record any stock-based compensation costs related to Incentive RSUs for the three and six months ended June 30, 2016. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of June 30, 2017, there was $32.8 million of total unrecognized compensation cost related to the unvested Incentive RSUs granted to certain employees that is expected to be recognized over a weighted average period of 2.3 years.

The following table summarizes the Incentive RSU activity from January 1, 2017 through June 30, 2017 and provides information for Incentive RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested Incentive RSUs at January 1, 2017	2,714,368	$ 20.45
Granted	—	$ —
Forfeited	(685,568)	$ 20.45
Vested	—	$ —
Non-vested Incentive RSUs at June 30, 2017	2,028,800	$ 20.45

Unit-Based Compensation

The Company recorded $1.2 million and $2.6 million of unit-based compensation costs related to restricted unit awards for the three and six months ended June 30, 2016, respectively. There was no unrecognized compensation costs related to these restricted unit awards as of June 30, 2017. For additional disclosure regarding these restricted unit awards, see the Company's Annual Report.

Note 10—Earnings (Loss) Per Share

Basic earnings per share ("EPS") includes no dilution and is computed by dividing net income (loss) available to common shareholders by the weighted average number of shares outstanding during the period. Diluted EPS reflects the potential dilution of securities that could share in the earnings of the Company.

The Company uses the "if-converted" method to determine potential dilutive effects of the Company's outstanding Series A Preferred Stock (the "Series A Preferred Stock") and the treasury method to determine the potential dilutive effects of outstanding restricted stock awards and stock options. The basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding for the three and six months ended June 30, 2017. EPS information is not applicable for the three and six months ended June 30, 2016.

The components of basic and diluted EPS were as follows (in thousands, except per share data):

	For the Three Months Ended June 30, 2017	For the Six Months Ended June 30, 2017
Basic and Diluted Earnings Per Share		
Net Income	$ 7,240	$ 15,956
Less: Adjustment to reflect Series A Preferred Stock dividend	(2,722)	(5,443)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	(1,331)	(2,627)
Adjusted net income available to common shareholders, basic and diluted	$ 3,187	$ 7,886
Denominator:		
Weighted average common shares outstanding, basic and diluted [(1)]	171,835	171,835
Earnings Per Common Share		
Basic and diluted	$ 0.02	$ 0.05

(1) For the three and six months ended June 30, 2017, the diluted EPS calculation excludes the dilutive effect of 4,500,000 common shares for stock options that were out-of-the-money, the anti-dilutive effect of 4,071,683 RSUs and the anti-dilutive effect of 11,472,445 common shares issuable for Series A Preferred Stock under the if-converted method.

Note 11—Commitments and Contingencies

Leases

The Company leases two office spaces in Denver, Colorado, one office space in Greeley, Colorado and one office space in Houston, Texas under separate operating lease agreements. The Denver, Colorado leases expire on February 29, 2020 and May 31, 2026, respectively. The Greeley and Houston leases expire on August 31, 2019 and October 31, 2017, respectively. Total rental commitments under non-cancelable leases for office space were $20.2 million at June 30, 2017. The future minimum lease payments under these non-cancelable leases are as follows: $1.3 million in 2017, $2.6 million in 2018, $2.5 million in 2019, $2.2 million in 2020, $2.1 million in 2021 and $9.5 million thereafter. Rent expense was $0.6 million and $1.2 million for the three and six months ended June 30, 2017, respectively, as compared to $0.4 million and 0.7 million for the three and six months ended June 30, 2016, respectively.

On June 4, 2015, the Company subleased the remaining term of one of its Denver office leases that expires February 29, 2020. The sublease will decrease the Company's future lease payments by $0.6 million.

Drilling Rigs

As of June 30, 2017, the Company was subject to commitments on four drilling rigs. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate amount of approximately $12.3 million as of June 30, 2017, as required under the terms of the contracts. The fourth rig is expected to be placed in service during the fourth quarter of 2017 and will replace a rig currently under contract.

Delivery Commitments

As of June 30, 2017, the Company's oil marketer was subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. The Company amended its agreement with its oil marketer that requires it to sell all of its crude oil from an area of mutual interest in exchange for a make-whole provision that allows the Company to satisfy any minimum volume commitment deficiencies incurred by its oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. The Company evaluates its contracts for loss contingencies and accrues for such losses, if the loss can be reasonably estimated and deemed probable. The Company also has one long-term crude oil gathering commitment with an unconsolidated affiliate. It has a term of ten years for an average of 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The aggregate amount of estimated payments under these agreements is $1.0 billion.

In collaboration with several other producers and a midstream provider, on December 15, 2016, the Company agreed to participate in the expansion of natural gas gathering and processing capacity in the DJ Basin. The plan includes a new processing plant as well as the expansion of a related gathering system, both currently expected to be completed by late 2018, although the start-up date is undetermined at this time. The Company's share of the commitment will require 51.5 MMcf per day to be delivered after the plant in-service date for a period of seven years thereafter. The Company may be required to pay a shortfall fee for any volumes under the 51.5 MMcf per day commitment. This contractual obligation can be reduced by the Company's proportionate share of the collective volumes delivered to the plant by other third party incremental volumes available to the midstream provider at the new facility that are in excess of the total commitment. The Company is also required for the first three years of the contract to guarantee a certain target profit margin on these volumes sold. Under its current drilling plans, the Company expects to meet the volume commitment.

None of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers. The Company believes that its future production is adequate to meet its commitments. If for some reason the Company's production is not sufficient to satisfy its commitments, the Company expects to be able to purchase volumes in the market or make other arrangements to satisfy its commitments.

Acquisition of Undeveloped Leasehold Acreage

As of June 30, 2017, the Company is party to an agreement with an unrelated third party for which it has paid $37.5 million and may be required to pay up to an additional $108.6 million, subject to certain customary conditions, to lease up to a total of 29,200 net acres of undeveloped leasehold.

General

The Company is subject to contingent liabilities with respect to existing or potential claims, lawsuits and other proceedings, including those involving environmental, tax and other matters, certain of which are discussed more specifically below. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company’s estimates of the outcomes of these matters and its experience in contesting, litigating and settling other matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which management currently believes will not have a material effect on the Company’s financial position, results of operations or cash flows.

As is customary in the oil and gas industry, the Company may at times have commitments in place to connect wells to gathering and transportation services and reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost or the Company may be required to pay damages if certain performance conditions are not met.

Legal Matters

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on the Company’s financial position, results of operations or cash flows. Management is unaware of any pending litigation brought against the Company requiring the reserve of a contingent liability as of the date of this filing.

The Company is currently in discussions with the Colorado Department of Public Health and Environment (“CDPHE”) regarding a Compliance Advisory issued to the Company in July 2015, which alleged air quality violations at three Company facilities regarding leakages of volatile organic compounds from storage tanks, all of which were promptly addressed. The Company continues to work with the CDPHE on its investigation into the Company's facilities and it intends to seek a field-wide administrative settlement of these issues. At this time, the Company cannot predict the outcome of this matter at this time or the remediation or the compliance costs that this matter may impose on the Company.

Note 12—Related Party Transactions

Office Lease with Related Affiliate

In April 2016, the Company subleased office space to Star Peak Capital, LLC, of which a member of the board of directors is an owner, for $1,400 per month. The sublease commenced on May 1, 2016 and expires on February 28, 2020.

2021 Senior Notes

Several lenders of the 2021 Senior Notes are also 5% stockholders of the Company. As of the initial issuance in July 2016 of the $550.0 million principal amount on the 2021 Senior Notes, such stockholders held $63.5 million.

2024 Senior Notes

Several lenders of the 2024 Senior Notes are also 5% stockholders of the Company. As of the initial issuance in August 2017 of the $400.0 million principal amount on the 2024 Senior Notes, such stockholders held $54.9 million.

Series A Preferred Stock

Several holders of the Series A Preferred Stock are also 5% stockholders of the Company. As of the initial issuance in October 2016 of the $185.3 million of Series A Preferred Stock, such stockholders held $105.0 million.

Long-Term Crude Oil Gathering Commitment

The Company has a long-term crude oil gathering commitment with an unconsolidated affiliate. It has a term of ten years for an average of 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d in years three through five and 10,000 Bbl/d in years six through ten. The aggregate amount of estimate payments under this agreement is $71.9 million.

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (“Quarterly Report”) contains "forward-looking statements." All statements, other than statements of historical facts, included or incorporated by reference herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. For such statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- federal and state regulations and laws;
- capital requirements and uncertainty of obtaining additional funding on terms acceptable to us;
- risks and restrictions related to our debt agreements;
- our ability to use derivative instruments to manage commodity price risk;
- realized oil, natural gas and NGL prices;
- a decline in oil, natural gas and NGL production and the impact of general economic conditions on the demand for oil, natural gas and NGL and the availability of capital;
- unsuccessful drilling and completion activities and the possibility of resulting write-downs;
- geographical concentration of our operations;
- our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil or natural gas in commercially viable quantities;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- adverse variations from estimates of reserves, production, production prices and expenditure requirements, and our inability to replace our reserves through exploration and development activities;
- incorrect estimates associated with properties we acquire relating to estimated proved reserves, the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs of such acquired properties;
- hazardous, risky drilling operations, including those associated with the employment of horizontal drilling techniques, and adverse weather and environmental conditions;
- limited control over non-operated properties;
- title defects to our properties and inability to retain our leases;
- our ability to successfully develop our large inventory of undeveloped operated and non-operated acreage;
- our ability to retain key members of our senior management and key technical employees;
- constraints in the DJ Basin of Colorado with respect to gathering, transportation and processing facilities and marketing;
- risks relating to managing our growth, particularly in connection with the integration of significant acquisitions;
- impact of environmental, health and safety and other governmental regulations, and of current or pending legislation;
- changes in tax laws;
- effects of competition; and

- seasonal weather conditions.

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

In addition to the other information and risk factors set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading “Risk Factors” included in our Annual Report on Form 10-K for the year ended December 31, 2016 (our “Annual Report”) and in our other filings with the Securities Exchange Commission, which could materially affect our businesses, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. There has been no material changes in our risk factors from those described in our Annual Report.

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Quarterly Report. Except as required by law, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Management’s Discussion and Analysis of Financial Condition and Results of Operations (“MD&A”) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company’s operating results. MD&A should be read in conjunction with the Condensed Consolidated Financial Statements and related Notes included in Part I, Item 1 of this Quarterly Report. The following information updates the discussion of the Company’s financial condition provided in its Annual Report and analyzes the changes in the results of operations between the three and six months ended June 30, 2017 and 2016.

EXECUTIVE SUMMARY

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the DJ Basin. We have developed an oil, natural gas and NGL asset base of proved reserves, as well as a portfolio of development drilling opportunities on high resource-potential leasehold on contiguous acreage blocks in some of the most productive areas of what we consider to be the core of the DJ Basin. We are focused on growing our proved reserves and production primarily through the development of our large inventory of identified liquids-rich horizontal drilling locations.

Financial Results

For the three and six months ended June 30, 2017, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to $119.9 million and $200.5 million, respectively, as compared to $65.7 million and $138.3 million, respectively, in the same prior year periods due to an increase in sales volumes of 1,507 MBoe and 2,258 MBoe, respectively. The increase in crude oil, natural gas and NGL sales for the three months ended June 30, 2017 as compared to the same prior year period was also due to an increase of $3.67 in realized price per BOE, including settled derivatives. The increase in crude oil, natural gas NGL sales for the six months ended June 30, 2017, as compared to the prior period was offset by a decrease of $0.47 in realized price per BOE, including settled derivatives.

For the three and six months ended June 30, 2017, we had net income of $7.2 million and $16.0 million, respectively, as compared to net loss of $127.6 million and $173.1 million for the three and six months ended June 30, 2016, respectively. The increase to net income was primarily driven by an increase in commodity derivatives of $108.5 million and $162.9 million, respectively, and an increase in sales revenues of $54.4 million and $98.9 million, respectively. These increases to net income were offset by an increase in operating expenses of $27.9 million and $72.0 million, respectively, primarily related to the increased sales volumes.

Adjusted EBITDAX was $74.9 million and $117.3 million for the three and six months ended June 30, 2017, respectively, as compared to $39.4 million and $89.8 million for the three and six months ended June 30, 2016, respectively, reflecting a 89.9% and 30.6% increase, respectively. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please read "—Adjusted EBITDAX."

Operational Results

During the three months ended June 30, 2017, our aggregate drilling, completion, leasehold and midstream capital expenditures, excluding acquisitions and business combinations, totaled $271.8 million, $239.6 million of which was drilling and completion. We invested $30.3 million on leasehold and $1.9 million for midstream. Our total drilling and completion capital expenditures for the six months ended June 30, 2017 were approximately $448.8 million, including $20.1 million for non-operated drilling and completion.

We reached total depth on 41 gross (25 net) wells with an average lateral length of approximately 10,100 feet and completed 51 gross (46 net) wells with an average lateral length of approximately 7,300 feet. We turned to sales 67 gross (62 net) wells with an average lateral length of approximately 7,100 feet. Thirty three gross (31 net) wells with an average lateral length of approximately 8,200 feet were turned on in the back half of the second quarter and contributed little to second quarter production since they were still in various stages of cleanup. These 33 wells are expected to contribute significantly to third quarter volumes. We completed 2,474 total fracturing stages during the quarter while pumping approximately 854 million pounds of proppant.

Recent Developments

July 2017 Acquisition

On July 7, 2017, we acquired interests in approximately 12,500 net acres of leasehold, and related producing and non-producing properties located in the DJ Basin, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets from an unaffiliated third party. The seller received total consideration of $84.0 million in cash, subject to customary purchase price adjustments.

2024 Senior Notes

On August 1, 2017, we issued at par $400.0 million principal amount of 7.375% Senior Notes due May 15, 2024 (the "2024 Senior Notes" and the offering, the "2024 Senior Notes Offering"). The 2024 Senior Notes bear an annual interest rate of 7.375%. The interest on the 2024 Senior Notes is payable on May 15 and November 15 of each year commencing on November 15, 2017. We received net proceeds of approximately $392.8 million after deducting discounts and fees. We intends to use the net proceeds from the 2024 Senior Notes Offering to partially fund our 2017 capital expenditures and for general corporate purposes.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and gas operations, including:

- Sources of revenue;
- Sales volumes;
- Realized prices on the sale of oil, natural gas and NGL, including the effect of our commodity derivative contracts;
- Lease operating expenses ("LOE");
- Capital expenditures; and
- Adjusted EBITDAX (a Non-GAAP measure).

Sources of Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGL that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives. For the three months ended June 30, 2017, our revenues were derived 71% from oil sales, 15% from natural gas sales and 13% from NGL sales. For the three months ended June 30, 2016, our revenues were derived 77% from oil sales, 13% from natural gas sales and 11% from NGL sales. For the six months ended June 30, 2017, our revenues were derived 66% from oil sales, 18% from natural gas sales and 16% from NGL sales. For the six months ended June 30, 2016, our revenues were derived 76% from oil sales, 14% from natural gas sales and 10% from NGL sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Sales Volumes

The following table presents historical sales volumes for our properties for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Oil (MBbl)	2,101	1,259	3,312	2,518
Natural gas (MMcf)	6,402	4,541	12,761	8,061
NGL (MBbl)	852	497	1,585	905
Total (MBoe)	4,020	2,512	7,024	4,766
Average net sales (BOE/d)	44,172	27,609	38,807	26,187

As reservoir pressure declines, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through organic growth as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including takeaway capacity in our areas of operation and our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read "Risks Related to the Oil, Natural Gas and NGL Industry and Our Business" in Item 1A. of our Annual Report for a further description of the risks that affect us.

Realized Prices on the Sale of Oil, Natural Gas and NGL

Our results of operations depend upon many factors, particularly the price of oil, natural gas and NGL and our ability to market our production effectively. Oil, natural gas and NGL prices are among the most volatile of all commodity prices. For example, during the period from January 1, 2014 to June 30, 2017, NYMEX West Texas Intermediate oil prices ranged from a high of $107.26 per Bbl to a low of $26.21 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $6.15 per MMBtu to a low of $1.64 per MMBtu during the same period. Declines in, and continued depression of, the price of oil and natural gas occurring during 2015 and continuing into 2017 are due to a combination of factors including increased U.S. supply, global economic concerns and geopolitical risks. These price variations can have a material impact on our financial results and capital expenditures.

Oil pricing is predominately driven by the physical market, supply and demand, financial markets and national and international politics. The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. In the DJ Basin, oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGL. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. The price we receive for our natural gas produced in the DJ Basin is based on CIG prices, adjusted for certain deductions.

Our price for NGL produced in the DJ Basin is based on a combination of prices from the Conway hub in Kansas and Mont Belvieu in Texas where this production is marketed.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. The differential varies, but our oil, natural gas and NGL normally sells at a discount to the NYMEX WTI and NYMEX Henry Hub price, as applicable.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Oil				
NYMEX WTI High ($/Bbl)	$ 53.40	$ 51.23	$ 54.45	$ 51.23
NYMEX WTI Low ($/Bbl)	$ 42.53	$ 35.70	$ 42.53	$ 26.21
NYMEX WTI Average ($/Bbl)	$ 48.15	$ 45.64	$ 49.95	$ 39.78
Average Realized Price ($/Bbl)	$ 40.64	$ 39.76	$ 41.52	$ 33.41
Average Realized Price, with derivative settlements ($/Bbl)	$ 40.70	$ 36.74	$ 39.14	$ 41.51
Average Realized Price as a % of Average NYMEX WTI	84.4%	87.1%	83.1%	84.0%
Differential ($/Bbl) to Average NYMEX WTI	$ (7.51)	$ (5.88)	$ (8.43)	$ (6.37)
Natural Gas				
NYMEX Henry Hub High ($/MMBtu)	$ 3.42	$ 2.92	$ 3.42	$ 2.92
NYMEX Henry Hub Low ($/MMBtu)	$ 2.89	$ 1.90	$ 2.56	$ 1.64
NYMEX Henry Hub Average ($/MMBtu)	$ 3.14	$ 2.25	$ 3.10	$ 2.12
Average Realized Price ($/Mcf)	$ 2.89	$ 1.83	$ 3.01	$ 1.85
Average Realized Price, with derivative settlements ($/Mcf)	$ 2.90	$ 2.76	$ 2.94	$ 2.77
Average Realized Price as a % of Average NYMEX Henry Hub(1)	83.9%	74.2%	88.3%	79.6%
Differential ($/Mcf) to Average NYMEX Henry Hub(1)	$ (0.56)	$ (0.64)	$ (0.40)	$ (0.48)
NGL				
Average Realized Price ($/Bbl)	$ 18.61	$ 14.06	$ 21.10	$ 12.63
Average Realized Price as a % of Average NYMEX WTI	38.6%	30.8%	42.2%	31.8%

(1) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf using a conversion factor of 1.1 to 1.

Derivative Arrangements

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our oil and natural gas production. By removing a significant portion of price volatility associated with our oil and natural gas production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will realize gains to the extent our derivatives contract prices are higher than market prices. In certain circumstances, where we have unrealized gains in our derivative portfolio, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. See "—Quantitative and Qualitative Disclosure About Market Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. As a result of recent volatility in the price of oil and natural gas, we have relied on a variety of hedging strategies and instruments to hedge our future price risk. We have utilized swaps, put options and call options, which in some instances require the payment of a premium, to reduce the effect of price changes on a portion of our future oil and natural gas production. We expect to continue to use a variety of hedging strategies and instruments for the foreseeable future.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of our purchased put options have deferred premiums. For the deferred premium puts, we agreed to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

We combine swaps, purchased put options, sold put options and sold call options in order to achieve various hedging strategies. Some examples of our hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap. We have historically relied on commodity derivative contracts to mitigate our exposure to lower commodity prices.

We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements at favorable prices may be limited, and, we are not obligated to hedge a specific portion of our oil or natural gas production. The following summarizes our derivative positions related to crude oil and natural gas sales in effect as of June 30, 2017:

	2017	2018
NYMEX WTI[1] Crude Swaps:		
Notional volume (Bbl)	—	4,500,000
Weighted average fixed price ($/Bbl)		$ 51.76
NYMEX WTI[1] Crude Sold Calls:		
Notional volume (Bbl)	4,500,000	2,500,000
Weighted average sold call price ($/Bbl)	$ 56.40	$ 60.61
NYMEX WTI[1] Crude Sold Puts:		
Notional volume (Bbl)	4,250,000	6,600,000
Weighted average sold put price ($/Bbl)	$ 38.41	$ 39.64
NYMEX WTI[1] Crude Purchased Puts:		
Notional volume (Bbl)	4,500,000	2,400,000
Weighted average purchased put price ($/Bbl)	$ 47.94	$ 50.50
NYMEX HH[2] Natural Gas Swaps:		
Notional volume (MMBtu)	14,840,000	34,800,000
Weighted average fixed price ($/MMBtu)	$ 3.06	$ 3.11
NYMEX HH[2] Natural Gas Purchased Puts:		
Notional volume (MMBtu)	—	2,400,000
Weighted average purchased put price ($/MMBtu)		$ 3.00
NYMEX HH[2] Natural Gas Sold Calls:		
Notional volume (MMBtu)	—	2,400,000
Weighted average sold call price ($/MMBtu)		$ 3.15
CIG[3] Basis Gas Swaps:		
Notional volume (MMBtu)	8,895,000	6,300,000
Weighted average fixed basis price ($/MMBtu)	$ (0.34)	$ (0.31)

(1) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange
(2) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange
(3) CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) settlement price.

The following table summarizes our historical derivative positions and the settlement amounts for each of the periods indicated.

	For the Six Months Ended June 30,	
	2017	2016
NYMEX HH[(1)] Natural Gas Swaps:		
Notional volume (MMBtu)	10,580,000	6,418,594
Weighted average fixed price ($/MMBtu)	$ 3.04	$ 3.16
CIG[(3)] Basis Gas Swaps:		
Notional volume (MMBtu)	3,720,000	990,000
Weighted average fixed basis price ($/MMBtu)	$ (0.33)	(0.19)
NYMEX WTI[(2)] Crude Swaps:		
Notional volume (Bbl)	1,500,000	912,389
Weighted average fixed price ($/Bbl)	$ 43.84	$ 45.17
NYMEX WTI[(2)] Crude Sold Puts:		
Notional volume (Bbl)	1,770,000	800,000
Weighted average strike price ($/Bbl)	$ 36.15	$ 44.81
NYMEX WTI[(2)] Crude Purchased Puts:		
Notional volume (Bbl)	1,370,000	2,697,479
Weighted average strike price ($/Bbl)	$ 46.64	$ 51.57
NYMEX WTI[(2)] Crude Sold Calls:		
Notional volume (Bbl)	1,370,000	1,457,090
Weighted average strike price ($/Bbl)	$ 54.46	$ 63.12
NYMEX WTI[(2)] Crude Purchased Calls:		
Notional volume (Bbl)	—	134,000
Weighted average strike price ($/Bbl)		$ 69.63
Total Amounts Received/(Paid) from Settlement (in thousands)	**$ (9,184)**	**$ 33,160**
Cash provided by (used in) changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	$ (4,056)	$ 9,024
Cash Settlements on Commodity Derivatives per Consolidated Statements of Cash Flows	**$ (13,240)**	**$ 42,184**

(1) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange
(2) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange
(3) CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) settlement price.

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constitute part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, water injection and disposal costs, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition, drilling and completion expenses. LOE also includes expenses incurred to gather and deliver natural gas to the processing plant and/or selling point.

Capital Expenditures

For the six months ended June 30, 2017, we incurred approximately $448.8 million in capital expenditures in connection with the drilling of 88 gross (63 net) wells with an average lateral length of approximately 9,000 feet and completed 105 gross (96 net) wells with an average lateral length of approximately 7,100 feet. We turned to sales 93 gross (87 net) wells with an average lateral length of approximately 7,100 feet. In addition, we incurred approximately $51.4 million of leasehold and surface acreage additions and approximately $4.7 million of midstream and infrastructure additions, excluding amounts paid for asset acquisitions and business combinations.

Our 2017 capital budget is approximately $795 million to $935 million, substantially all of which we intend to allocate to the DJ Basin. We intend to allocate approximately $675 million to $775 million of our 2017 capital budget to the drilling of 185 to 190 gross operated wells and the completion of 190 to 195 gross operated wells, approximately $60 to $80 million of non-operated drilling and completion, and approximately $60 million to $80 million to undeveloped leasehold acquisitions, midstream, and other capital expenditures. We are currently running a three rig program and plan to remain with a three rig program throughout 2017. Our capital budget excludes any amounts that were or may be paid for potential acquisitions.

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGL, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and related standardized measure. These risks could materially affect our business, financial condition and results of operations.

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income (loss) as determined by United States generally accepted accounting principles ("GAAP"). Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depletion, depreciation, amortization and accretion ("DD&A"), impairment of long lived assets, exploration expenses, rig termination fees, acquisition transaction expenses, commodity derivative (gain) loss, settlements on commodity derivatives, premiums paid for derivatives that settled during the period, unit and stock-based compensation expense, amortization of debt discount and debt issuance costs, interest expense, income taxes and non-recurring charges.

Management believes Adjusted EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital, hedging strategy and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance. Additionally, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting. Adjusted EBITDAX is also used by our board of directors as a performance measure in determining executive compensation.

The following table presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income (loss) for each of the periods indicated (in thousands).

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:				
Net income (loss)	$ 7,240	$ (127,614)	$ 15,956	$ (173,134)
Add back:				
Depletion, depreciation, amortization and accretion	68,610	49,330	119,263	94,638
Impairment of long lived assets	—	22,438	675	22,884
Exploration expenses	6,438	5,921	17,250	8,752
Rig termination fee	—	—	—	891
Loss on sale of property and equipment	—	—	451	—
Acquisition transaction expenses	—	—	68	—
(Gain) loss on commodity derivatives	(33,876)	74,614	(84,298)	78,650
Settlements on commodity derivative instruments	(143)	2,658	(9,184)	33,160
Premiums paid for derivatives that settled during the period	313	(2,278)	313	(5,338)
Unit and stock-based compensation expense	12,852	1,238	28,597	2,606
Amortization of debt discount and debt issuance costs	867	1,227	1,712	2,425
Interest expense	8,154	11,903	16,969	24,273
Income tax expense	4,420	—	9,550	—
Adjusted EBITDAX	$ 74,875	$ 39,437	$ 117,322	$ 89,807

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for the reasons described below:

- On October 3, 2016, we acquired additional oil and gas properties primarily located in the Wattenberg Field located primarily around our existing Greeley and Windsor areas. The October 2016 Acquisition consisted of working interest in approximately 6,400 net acres and 31 gross (19 net) drilled but uncompleted wells, as of the date of acquisition. The October 2016 Acquisition provided net daily production of approximately 6,900 BOE/d during the fourth quarter 2016.
- As a result of the initial public offering (“IPO”), we expect to incur additional general and administrative expenses related to being a public company, including Exchange Act reporting expenses; expenses associated with Sarbanes-Oxley compliance; expenses associated with listing on the NASDAQ Global Select Market; incremental independent auditor fees; incremental legal fees; investor relations expenses; registrar and transfer agent fees; incremental director and officer liability insurance costs; and directors compensation.
- Prior to the Corporate Reorganization, we were not subject to federal or state income taxes. Accordingly, the financial data attributable to us prior to such corporate reorganization contain no provision for federal or state income taxes because the tax liability with respect to Holdings’ taxable income was passed through to our members. Beginning October 12, 2016, we began to be taxed as a C corporation under the Internal Revenue Code and subject to federal and state income taxes at a blended statutory rate of approximately 38% of pretax earnings.

Historical Results of Operations and Operating Expenses

Oil, Natural Gas and NGL Sales Revenues, Operating Expenses and Other Income (Expense).

The following table provides the components of our revenues, operating expenses, other income (expense) and net income (loss) for the periods indicated (in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
	(Unaudited)			
Revenues:				
Oil sales	$ 85,394	$ 50,047	$ 137,522	$ 84,135
Natural gas sales	18,526	8,331	38,423	14,937
NGL sales	15,846	6,986	33,460	11,424
Total Revenues	119,766	65,364	209,405	110,496
Operating Expenses:				
Lease operating expenses	24,165	13,369	46,488	25,339
Production taxes	10,511	6,258	16,964	10,748
Exploration expenses	6,438	5,921	17,250	8,752
Depletion, depreciation, amortization and accretion	68,610	49,330	119,263	94,638
Impairment of long lived assets	—	22,438	675	22,884
Other operating expenses	—	—	451	891
Acquisition transaction expenses	—	—	68	—
General and administrative expenses	23,487	7,974	49,175	15,114
Total Operating Expenses	133,211	105,290	250,334	178,366
Operating Loss	(13,445)	(39,926)	(40,929)	(67,870)
Other Income (Expense):				
Commodity derivatives gain (loss)	33,876	(74,614)	84,298	(78,650)
Interest expense	(9,021)	(13,130)	(18,681)	(26,698)
Other income	250	56	818	84
Total Other Income (Expense)	25,105	(87,688)	66,435	(105,264)
Income (Loss) Before Income Taxes	11,660	(127,614)	25,506	(173,134)
Income tax expense	4,420	—	9,550	—
Net Income (Loss)	$ 7,240	$ (127,614)	$ 15,956	$ (173,134)

The following table provides a summary of our sales volumes, average prices and operating expenses on a per BOE basis for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Sales (MBoe)[1]:	4,020	2,512	7,024	4,766
Oil sales (MBbl)	2,101	1,259	3,312	2,518
Natural gas sales (MMcf)	6,402	4,541	12,761	8,061
NGL sales (MBbl)	852	497	1,585	905
Sales (BOE/d)[1]:	44,172	27,609	38,807	26,187
Oil sales (Bbl/d)	23,088	13,831	18,298	13,835
Natural gas sales (Mcf/d)	70,353	49,898	70,501	44,289
NGL sales (Bbl/d)	9,358	5,462	8,759	4,970
Average sales prices[2]:				
Oil sales (per Bbl)	$ 40.64	$ 39.76	$ 41.52	$ 33.41
Oil sales with derivative settlements (per Bbl)	40.70	36.74	39.14	41.51
Natural gas sales (per Mcf)	2.89	1.83	3.01	1.85
Natural gas sales with derivative settlements (per Mcf)	2.90	2.76	2.94	2.77
NGL sales (per Bbl)	18.61	14.06	21.10	12.63
Average price per BOE	29.80	26.02	29.81	23.18
Average price per BOE with derivative settlements	29.84	26.17	28.55	29.02
Expense per BOE:				
Lease operating expenses	$ 6.01	$ 5.32	$ 6.62	$ 5.32
Operating expenses	3.51	3.33	3.72	3.41
Transportation and gathering	2.50	1.99	2.90	1.91
Production taxes	2.61	2.49	2.42	2.26
Exploration expenses	1.60	2.36	2.46	1.84
Depletion, depreciation, amortization and accretion	17.07	19.63	16.98	19.86
Impairment of long lived assets	—	8.93	0.10	4.80
Other operating expenses	—	—	0.06	0.19
Acquisition transaction expenses	—	—	0.01	—
General and administrative expenses	5.84	3.17	7.00	3.17
Cash general and administrative expenses	2.64	2.68	2.93	2.62
Unit and stock-based compensation	3.20	0.49	4.07	0.55
Total operating expenses per BOE	$ 33.13	$ 41.90	$ 35.65	$ 37.44

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) Average prices shown in the table reflect prices both before and after the effects of our settlements of our commodity derivative contracts. Our calculation of such effects includes both gains and losses on settlements for commodity derivatives and amortization of premiums paid or received on options that settled during the period.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Oil sales revenues. Crude oil sales revenues increased by $35.4 million to $85.4 million for the three months ended June 30, 2017 as compared to crude oil sales of $50.0 million for the three months ended June 30, 2016. An increase in sales volumes between these periods contributed a $33.5 million positive impact, while an increase in crude oil prices contributed a $1.9 million positive impact.

For the three months ended June 30, 2017, our crude oil sales averaged 23.1 MBbl/d. Our crude oil sales volume increased 67% to 2,101 MBbl for the three months ended June 30, 2017 compared to 1,259 MBbl for the three months ended June 30, 2016. The volume increase is primarily due to an increase in production from the completion of 144 gross wells from July 1, 2016 to June 30, 2017, partially offset by the natural decline of our existing properties.

The average price we realized on the sale of crude oil was $40.64 per Bbl for the three months ended June 30, 2017 compared to $39.76 per Bbl for the three months ended June 30, 2016.

Natural gas sales revenues. Natural gas revenues increased by $10.2 million to $18.5 million for the three months ended June 30, 2017 as compared to natural gas revenues of $8.3 million for the three months ended June 30, 2016. An increase in sales volumes between these periods contributed a $3.4 million positive impact, while an increase in natural gas prices contributed a $6.8 million positive impact due to increasing natural gas prices.

For the three months ended June 30, 2017, our natural gas sales averaged 70.4 MMcf/d. Natural gas sales volumes increased by 41% to 6,402 MMcf for the three months ended June 30, 2017 as compared to 4,541 MMcf for the three months ended June 30, 2016. The volume increase is primarily due to the completion of 144 gross wells from July 1, 2016 to June 30, 2017, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $2.89 per Mcf for the three months ended June 30, 2017 compared to $1.83 per Mcf for the three months ended June 30, 2016.

NGL sales revenues. NGL revenues increased by $8.8 million to $15.8 million for the three months ended June 30, 2017 as compared to NGL revenues of $7.0 million for the three months ended June 30, 2016. An increase in sales volumes between these periods contributed a $5.0 million positive impact, while an increase in price contributed a $3.8 million positive impact.

For the three months ended June 30, 2017, our NGL sales averaged 9.4 MBbl/d. NGL sales volumes increased by 71% to 852 MBbl for the three months ended June 30, 2017 as compared to 497 MBbl for the three months ended June 30, 2016. The volume increase is primarily due to the completion of 144 gross wells from July 1, 2016 to June 30, 2017, partially offset by the natural decline on existing producing properties. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $18.61 per Bbl for the three months ended June 30, 2017 compared to $14.06 per Bbl for the three months ended June 30, 2016.

Lease operating expenses. Our LOE increased by $10.8 million to $24.2 million for the three months ended June 30, 2017, from $13.4 million for the three months ended June 30, 2016.

On a per unit basis, LOE increased from $5.32 per BOE sold for the three months ended June 30, 2016 to $6.01 per BOE sold for the three months ended June 30, 2017. The increase in LOE was comprised of an increase in transportation and gathering (“T&G”) expense of $5.0 million for the three months ended June 30, 2017 compared to the three months ended June 30, 2016 and an increase in operating expenses of $5.8 million for the three months ended June 30, 2017 compared to the three months ended June 30, 2016. The increase in LOE was primarily the result of an increase in both residue natural gas and NGL sales volumes and realized prices, resulting in collectively higher T&G fees.

Production taxes. Our production taxes increased by $4.2 million to $10.5 million for the three months ended June 30, 2017 as compared to $6.3 million for the three months ended June 30, 2016. The increase is primarily attributable to increased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 8.8% for the three months ended June 30, 2017 as compared to 9.6% for the three months ended June 30, 2016. The decrease in production taxes as a percentage of sales revenue relates to a change in the estimated tax rate for the three months ended June 30, 2017, as well as a refund of severance tax recorded in the same period.

Exploration expenses. Our exploration expenses were $6.4 million for the three months ended June 30, 2017. We recognized $4.6 million in expense attributable to the extension of certain leases and $1.8 million in impairment expense attributable to the abandonment and impairment of unproved properties for the three months ended June 30, 2017. For the three months ended June 30, 2016, we recognized $5.9 million in exploration expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $19.3 million to $68.6 million for the three months ended June 30, 2017 as compared to $49.3 million for the three months ended June 30, 2016. This increase is due to an increase in volumes sold for the three months ended June 30, 2017 as sales increased by approximately 1,507 MBoe. On a per unit basis, DD&A expense decreased from $19.63 per BOE for the three months ended June 30, 2016 to $17.07 per BOE for the three months ended June 30, 2017.

Impairment of long lived assets. We recognized no impairment expense for the three months ended June 30, 2017. We recognized $22.4 million of impairment expense for the three months ended June 30, 2016. The impairment expense for the three months ended June 30, 2016 is related to impairment of the assets in our northern field. The future undiscounted cash flows did not exceed the carrying amount associated with the proved oil and gas properties in the northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties was impaired at June 30, 2016.

General and administrative expenses. General and administrative ("G&A") expenses increased by $15.5 million to $23.5 million for the three months ended June 30, 2017 as compared to $8.0 million for the three months ended June 30, 2016. This increase is primarily due to an increase in our employee head count and stock-based compensation for the three months ended June 30, 2017 compared to the three months ended June 30, 2016. On a per unit basis, G&A expense increased from $3.17 per BOE sold for the three months ended June 30, 2016 to $5.84 per BOE sold for the three months ended June 30, 2017.

Our G&A expenses include the non-cash expense for unit and stock-based compensation for equity awards granted to our employees and directors. For the three months ended June 30, 2017, stock-based compensation expense was $12.9 million as compared to unit-based compensation of $1.2 million for the three months ended June 30, 2016. The increase is due to additional equity awards granted to employees as part of our 2016 Long Term Incentive Plan that was adopted in October 2016 in connection with our IPO.

Commodity derivative gain (loss). Primarily due to the decrease in NYMEX crude oil futures prices at June 30, 2017 as compared to March 31, 2017 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $33.9 million for the three months ended June 30, 2017. Primarily due to the increase in NYMEX crude oil futures prices at June 30, 2016 as compared to March 31, 2016 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $74.6 million for the three months ended June 30, 2016, including the amortization of premiums. These gains and losses are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program in the future. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the three months ended June 30, 2017, we paid cash settlements of commodity derivatives totaling $0.1 million. During the three months ended June 30, 2016, we received cash settlements of commodity derivatives totaling $2.7 million.

Interest expense. Interest expense consists of interest expense on our long term debt, amortization of debt discount and debt issuance costs, net of capitalized interest. For the three months ended June 30, 2017, we recognized interest expense of approximately $9.0 million as compared to $13.1 million for the three months ended June 30, 2016, as a result of borrowings under our revolving credit facility, Second Lien Notes in 2016, our 2021 Senior Notes and the amortization of debt issuance costs and debt discount.

We incurred interest expense for the three months ended June 30, 2017 of approximately $11.3 million related to our 2021 Senior Notes and credit facility. We incurred interest expense for the three months ended June 30, 2016 of approximately $13.3 million related to our credit facility and Second Lien Notes. Also included in interest expense for the three months ended June 30, 2017 and 2016 was the amortization of debt issuance costs and debt discount of $0.9 million and $1.2 million, respectively. For the three months ended June 30, 2017 and 2016, we capitalized interest expense of $3.2 million and $1.4 million, respectively.

Income tax expense. We recorded an income tax expense for the three months ended June 30, 2017 of $4.4 million, resulting in effective tax rate of approximately 37.9%. Our effective tax rate for 2017 differs from the U.S. statutory income tax rate primarily due to the effects of state income taxes and estimated permanent taxable differences. For 2017, our combined federal and state statutory tax rate was 38.0%. For the three months ended June 30, 2016, we were not subject to U.S. federal income tax.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

Oil sales revenues. Crude oil sales revenues increased by $53.4 million to $137.5 million for the six months ended June 30, 2017 as compared to crude oil sales of $84.1 million for the six months ended June 30, 2016. An increase in sales volumes between these periods contributed a $26.5 million positive impact, while an increase in crude oil prices contributed a $26.9 million positive impact.

For the six months ended June 30, 2017, our crude oil sales averaged 18.3 MBbl/d. Our crude oil sales volume increased 32% to 3,312 MBbl for the six months ended June 30, 2017 compared to 2,518 MBbl for the six months ended June 30, 2016. The volume increase is primarily due to an increase in production from the completion of 144 gross wells from July 1, 2016 to June 30, 2017, partially offset by the natural decline of our existing properties.

The average price we realized on the sale of crude oil was $41.52 per Bbl for the six months ended June 30, 2017 compared to $33.41 per Bbl for the six months ended June 30, 2016.

Natural gas sales revenues. Natural gas revenues increased by $23.5 million to $38.4 million for the six months ended June 30, 2017 as compared to natural gas revenues of $14.9 million for the six months ended June 30, 2016. An increase in sales volumes between these periods contributed an $8.7 million positive impact, while an increase in natural gas prices contributed a $14.8 million positive impact.

For the six months ended June 30, 2017, our natural gas sales averaged 70.5 MMcf/d. Natural gas sales volumes increased by 58% to 12,761 MMcf for the six months ended June 30, 2017 as compared to 8,061 MMcf for the six months ended June 30, 2016. The volume increase is primarily due to the completion of 144 gross wells from July 1, 2016 to June 30, 2017, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $3.01 per Mcf for the six months ended June 30, 2017 compared to $1.85 per Mcf for the six months ended June 30, 2016.

NGL sales revenues. NGL revenues increased by $22.1 million to $33.5 million for the six months ended June 30, 2017 as compared to NGL revenues of $11.4 million for the six months ended June 30, 2016. An increase in sales volumes between these periods contributed a $8.6 million positive impact, while an increase in price contributed a $13.5 million positive impact.

For the six months ended June 30, 2017, our NGL sales averaged 8.8 MBbl/d. NGL sales volumes increased by 75% to 1,585 MBbl for the six months ended June 30, 2017 as compared to 905 MBbl for the six months ended June 30, 2016. The volume increase is primarily due to the completion of 144 gross wells from July 1, 2016 to June 30, 2017, partially offset by the natural decline on existing producing properties. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $21.10 per Bbl for the six months ended June 30, 2017 compared to $12.63 per Bbl for the six months ended June 30, 2016.

Lease operating expenses. Our LOE increased by $21.2 million to $46.5 million for the six months ended June 30, 2017, from $25.3 million for the six months ended June 30, 2016.

On a per unit basis, LOE increased from $5.32 per BOE sold for the six months ended June 30, 2016 to $6.62 per BOE sold for the six months ended June 30, 2017. The increase in LOE was comprised of an increase in T&G expense of $11.2 million for the six months ended June 30, 2017 compared to the six months ended June 30, 2016 and an increase in operating expenses of $9.9 million for the six months ended June 30, 2017 compared to the six months ended June 30, 2016. The increase in LOE was primarily the result of an increase in both residue natural gas and NGL sales volumes and realized prices, resulting in collectively higher T&G fees.

Production taxes. Our production taxes increased by $6.3 million to $17.0 million for the six months ended June 30, 2017 as compared to $10.7 million for the six months ended June 30, 2016. The increase is primarily attributable to increased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 8.1% for the six months ended June 30, 2017 as compared to 9.7% for the six months ended June 30, 2016. The decrease in production taxes as a percentage of sales revenue relates to a change in the estimated tax rate for the six months ended June 30, 2017, as well as a refund of severance tax recorded in the same period.

Exploration expenses. Our exploration expenses were $17.3 million for the six months ended June 30, 2017. We recognized $12.7 million in expense attributable to the extension of certain leases and $4.6 million in impairment expense attributable to the abandonment and impairment of unproved properties for the six months ended June 30, 2017. For the six months ended June 30, 2016, we recognized $8.8 million in exploration expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $24.7 million to $119.3 million for the six months ended June 30, 2017 as compared to $94.6 million for the six months ended June 30, 2016. This increase is due to an increase in volumes sold for the six months ended June 30, 2017 as sales increased by approximately 2,258 MBoe. On a per unit basis, DD&A expense decreased from $19.86 per BOE for the six months ended June 30, 2016 to $16.98 per BOE for the six months ended June 30, 2017.

Impairment of long lived assets. Our impairment expense was $0.7 million for the six months ended June 30, 2017. We recognized this expense when certain well equipment inventory was evaluated to have a net realizable value less than the associated carrying value, after it was determined to no longer be useful in our current drilling operations. We recognized $22.9 million of impairment expense for the six months ended June 30, 2016. The impairment expense for the six months ended June 30, 2016 is primarily related to impairment of the assets in our northern field. The future undiscounted cash flows did not exceed the carrying amount associated with the proved oil and gas properties in the northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties was impaired at June 30, 2016.

Other operating expenses. Other operating expenses for the six months ended June 30, 2017 is comprised of a $0.5 million loss on the sale of property and equipment. Other operating expenses for the six months ended June 30, 2016 is comprised of a $0.9 million rig termination fee in January 2016.

General and administrative expenses. G&A expenses increased by $34.1 million to $49.2 million for the six months ended June 30, 2017 as compared to $15.1 million for the six months ended June 30, 2016. This increase is primarily due to an increase in our employee head count and stock-based compensation at for the six months ended June 30, 2017 compared to the six months ended June 30, 2016. On a per unit basis, G&A expense increased from $3.17 per BOE sold for the six months ended June 30, 2016 to $7.00 per BOE sold for the six months ended June 30, 2017.

Our G&A expenses include the non-cash expense for unit and stock-based compensation for equity awards granted to our employees and directors. For the six months ended June 30, 2017, stock-based compensation expense was $28.6 million as compared to unit-based compensation of $2.6 million for the six months ended June 30, 2016. The increase is due to additional equity awards granted to employees as part of our 2016 Long Term Incentive Plan that was adopted in October 2016 in connection with our IPO.

Commodity derivative gain (loss). Primarily due to the decrease in NYMEX crude oil futures prices at June 30, 2017 as compared to December 31, 2016 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $84.3 million for the six months ended June 30, 2017. Primarily due to the increase in NYMEX crude oil futures prices at June 30, 2016 as compared to December 31, 2015 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $78.7 million for the six months ended June 30, 2016, including the amortization of premiums. These gains and losses are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the six months ended June 30, 2017, we paid cash settlements of commodity derivatives totaling $9.2 million. During the six months ended June 30, 2016, we received cash settlements of commodity derivatives totaling $33.2 million.

Interest expense. Interest expense consists of interest expense on our long term debt, amortization of debt discount and debt issuance costs, net of capitalized interest. For the six months ended June 30, 2017, we recognized interest expense of approximately $18.7 million as compared to $26.7 million for the six months ended June 30, 2016, as a result of borrowings under our revolving credit facility, Second Lien Notes in 2016, our 2021 Senior Notes and the amortization of debt issuance costs and debt discount.

We incurred interest expense for the six months ended June 30, 2017 of approximately $22.6 million related to our 2021 Senior Notes and credit facility. We incurred interest expense for the six months ended June 30, 2016 of approximately $26.7 million related to our credit facility and Second Lien Notes. Also included in interest expense for the six months ended June 30, 2017 and 2016 was the amortization of debt issuance costs and debt discount of $1.7 million and $2.4 million, respectively. For the six months ended June 30, 2017 and 2016, we capitalized interest expense of $5.6 million and $2.4 million, respectively.

Income tax expense. We recorded an income tax expense for the six months ended June 30, 2017 of $9.6 million, resulting in effective tax rate of approximately 37.4%. Our effective tax rate for 2017 differs from the U.S. statutory income tax rate primarily due to the effects of state income taxes and estimated permanent taxable differences. For 2017, our combined federal and state statutory tax rate was 38.0%. For the six months ended June 30, 2016, we were not subject to U.S. federal income tax.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are cash flows generated by operating activities and borrowings under our revolving credit facility. Depending upon market conditions and other factors, we may also issue equity and debt securities if needed.

Historically, our primary sources of liquidity have been borrowings under our revolving credit facility, our Second Lien Notes, proceeds from the offerings of our 2021 Senior Notes and 2024 Senior Notes (please refer to *Note 4 – Long Term Debt)*, equity provided by investors, including our management team, proceeds from the IPO and a private placement of our common stock (the “Private Placement”) and cash flows from operations. To date, our primary use of capital has been for the acquisition of oil and gas properties to increase our acreage position, as well as development and exploration of oil and gas properties. Our borrowings, net of unamortized debt discount and debt issuance costs, were approximately $539.2 million and $538.1 million at June 30, 2017, and December 31, 2016, respectively. We also have other contractual commitments, which are described in *Note 11 – Commitments and Contingencies* in Part I, Item I, Financial Information of the Quarterly Report.

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 50% to 80% of our projected oil production over a one-to-two year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and available borrowings under our revolving credit facility to execute our current capital program, excluding any acquisitions we may consummate, make our interest payments on the 2021 and 2024 Senior Notes and pay dividends on our Series A Preferred Stock.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures and/or fund a portion of our capital expenditures using borrowings under our revolving credit facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot assure you that necessary capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our debt arrangements. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

Our 2017 capital budget is approximately $795 million to $935 million, substantially all of which we intend to allocate to the Core DJ Basin. We intend to allocate approximately $675 million to $775 million of our 2017 capital budget to the drilling of 185 to 190 gross operated wells and the completion of 190 to 195 gross operated wells, approximately $60 to $80 million of non-operated drilling and completion, and approximately $60 million to $80 million to undeveloped leasehold acquisitions, midstream, and other capital expenditures. We are currently running a three rig program and plan to remain with a three rig program throughout 2017.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	For the Six Months Ended June 30,	
	2017	2016
Net cash provided by operating activities	$ 65,827	$ 41,178
Net cash used in investing activities	$ (559,320)	$ (160,080)
Net cash provided by (used in) financing activities	$ (6,554)	$ 125,466

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

Net cash provided by operating activities. For the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, our net cash provided by operating activities increased by $24.6 million, primarily due to an increase in operating revenues, net of expenses, of $66.7 million from increased sales volumes and prices and an increase in cash due to changes in current assets and liabilities of $14.5 million for the six months ended June 30, 2017 compared to June 30, 2016. Offsetting these increases was a decrease in settlements on commodity derivatives of $55.4 million.

Net cash used in investing activities. For the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, our net cash used in investing activities increased by $399.2 million primarily due to an increase of $432.9 million used in acquisitions, drilling and completion activities and other property and equipment for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. Offsetting this increase was the change in cash held in escrow of $33.8 million.

Net cash provided by (used in) financing activities. For the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, our net cash provided by financing activities decreased by $132.0 million, as a result of a decrease of $117.0 million in proceeds from the issuance of units and a decrease of $10.0 million in proceeds from borrowings under our revolving credit facility. Additionally, for the six months ended June 30, 2017 compared to June 30, 2016 our net cash used in financing activities increased related to dividend payments on our Series A Preferred Stock of $5.0 million and our expenditures for equity issuance costs increased by $1.2 million.

Working Capital

Our working capital deficit was $62.2 million at June 30, 2017. Our working capital was $379.1 million at December 31, 2016. Our cash balances totaled $88.7 million and $588.7 million at June 30, 2017 and December 31, 2016, respectively.

Due to the amounts that we incur related to our drilling and completion program and the timing of such expenditures, we may incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our revolving credit facility after application of the net proceeds from the offering of the 2024 Senior Notes will be sufficient to fund our working capital needs. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil, natural gas and NGL production will be the largest variables affecting our working capital.

Debt Arrangements

Our revolving credit facility has a maximum credit amount of $1.0 billion, subject to a borrowing base, and all of our current and future subsidiaries will be guarantors under such facility. Amounts repaid under our revolving credit facility may be re-borrowed from time to time, subject to the terms of the facility. For more information on the revolving credit facility, please see *Note 4 — Long-Term Debt* in Part 1, Item 1. Financial Information of this Quarterly Report. The revolving credit facility is secured by liens on substantially all of our properties.

In July 2016, we closed a private offering of our unsecured 7.875% Senior Notes due 2021 ("2021 Senior Notes") that resulted in net proceeds of approximately $537.2 million. Our 2021 Senior Notes bear interest at an annual rate of 7.875%. Interest on our 2021 Senior Notes is payable on January 15 and July 15 of each year, and the first interest payment was made on

January 15, 2017. Our 2021 Senior Notes will mature on July 15, 2021. Our 2021 Senior Notes are guaranteed by all of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our 2021 Senior Notes).

In August 2017, we closed a private offering of our unsecured 7.375% Senior Notes due 2024 that resulted in net proceeds of approximately $392.8 million. Our 2024 Senior Notes bear interest at an annual rate of 7.375%. Interest on our 2024 Senior Notes is payable on May 15 and November 15 of each year commencing on November 15, 2017. Our 2024 Senior Notes will mature on May 15, 2024. Our 2024 Senior Notes are guaranteed by all of our current and future restricted subsidiaries.

Revolving Credit Facility

The amount available to be borrowed under our revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1, and will depend on the volumes of our proved oil and gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent under our revolving credit facility. As of June 30, 2017, the borrowing base was $475.0 million, and there were no borrowings outstanding under our revolving credit facility. In connection with the closing of the 2024 Senior Note offering, the Company's borrowing base was automatically reduced to $375.0 million.

Principal amounts borrowed will be payable on the maturity date, and interest will be payable quarterly for alternate base rate loans and at the end of the applicable interest period for Eurodollar loans. We have a choice of borrowing in Eurodollars or at the alternate base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the product of: (a) the LIBOR rate, multiplied by (b) a fraction (expressed as a decimal), the numerator of which is the number one and the denominator of which is the number one minus the reserve percentages (expressed as a decimal) on such date at which the administrative agent under our revolving credit facility is required to maintain reserves on ‘Eurocurrency Liabilities’ as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of our borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank’s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the adjusted one-month LIBOR rate (as calculated above) plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized. As of June 30, 2017, we had no outstanding borrowings under our revolving credit facility. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

The revolving credit facility is secured by liens on substantially all of our properties and guarantees from us and our current and future subsidiaries. The revolving credit facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- make certain changes to our capital structure;
- make or declare dividends;
- hedge future production or interest rates;
- enter into transactions with our affiliates;
- holding cash balances in excess of certain thresholds while carrying a balance of our revolving credit facility;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The revolving credit facility requires us to maintain the following financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (includes unused commitments under our revolving credit facility and unrestricted cash and excludes derivative assets) to our consolidated current liabilities (excludes obligations under our revolving credit facility, the senior notes and certain derivative liabilities), of not less than 1.0 to 1.0 as of the last day of any fiscal quarter; and

- a maximum leverage ratio, which is the ratio of (i) consolidated debt less cash balances in excess of certain thresholds to (ii) our consolidated EBITDAX for the four fiscal quarter period most recently ended, not to exceed 4.0 to 1.0 as of the last day of such fiscal quarter; provided that (a) for the quarters ending between December 31, 2016 through December 31, 2017, annualized EBITDAX will be based on the last six months' consolidated EBITDAX multiplied by 2, and (b) for the quarter ending March 31, 2018, annualized EBITDAX will be based on the last nine months' consolidated EBITDAX multiplied by 4/3, and (c) for the quarters ending on or after June 30, 2018, annualized EBITDAX will be based on the last twelve months' consolidated EBITDAX.

In March 2017, we amended the revolving credit facility to, among other things, allow (i) XTR Midstream, LLC, one of our subsidiaries ("XTR"), to make an investment in an unaffiliated third party, so long as (A) the aggregate amount of cash contributed by XTR to such entity does not exceed $5,000,000 and (B) the amount of cash and the fair market value of the assets contributed by XTR to such entity does not exceed $10,000,000 in the aggregate, and (ii) us to enter into a transportation agreement with a wholly-owned subsidiary of such entity.

In May 2017, we amended the revolving credit facility to, among other things, allow us to (i) incur obligations under our crude oil take-or-pay arrangements, together with certain other approved transportation agreements, not to exceed $50,000,000, subject to certain exceptions, (ii) incur exposure under letters of credit not to exceed $25,000,000 that name our oil marketer as the beneficiary thereof, and (iii) enter into certain hedging arrangements under an ISDA Master Agreement between us and our oil marketer.

We are in the process of negotiating an Amended and Restated Revolving Credit Facility with Wells Fargo Bank, National Association, and other unaffiliated third-party lenders that we expect to enter into during the third quarter of 2017. We expect that the terms of the Amended and Restated Revolving Credit Facility will extend the maturity of the Amended and Restated Revolving Credit Facility to five years from the date of the closing of the amendment and restatement, provided that in the event our existing 2021 Notes are not refinanced, we expect the maturity date of the Amended and Restated Revolving Credit Facility will be shortened to be at least six months prior to the scheduled maturity of the 2021 Notes. We expect to effect a borrowing base redetermination in connection with the entry into the Amended and Restated Revolving Credit Facility. There can be no assurance that we will be able to enter into the Amended and Restated Revolving Credit Facility, which will require (i) the lenders' satisfactory completion of their due diligence; (ii) the continued negotiation and execution and delivery of the amended and restated credit agreement and all related documents and legal opinions; (iii) delivery of officer's certificates, financial information and organizational documents; (iv) satisfaction of conditions related to perfection of liens; (v) obtaining all required consents; and (vi) payment of all fees and other amounts due to the lenders under the credit agreement.

We expect that the Amended and Restated Revolving Credit Facility will include certain financial and non-financial covenants, including, but not limited to, restrictions on incurring additional debt and certain distributions, similar to our current revolving credit facility. We also expect that the Amended and Restated Revolving Credit Facility will contain events of default customary for facilities of this nature.

Upon the occurrence and during the continuation of an event of default, subject to the terms and conditions of the Amended and Restated Revolving Credit Facility, we expect that the lenders will be able to declare any outstanding principal of the credit facility debt, together with accrued and unpaid interest, to be immediately due and payable and exercise other remedies.

2021 Senior Notes

In July 2016, we closed a private offering of our 2021 Senior Notes that resulted in net proceeds of approximately $537.2 million. Our 2021 Senior Notes bear interest at an annual rate of 7.875%. Interest on our 2021 Senior Notes is payable on January 15 and July 15 of each year, and the first interest payment was made on January 15, 2017. Our 2021 Senior Notes will mature on July 15, 2021.

We may, at our option, redeem all or a portion of our 2021 Senior Notes at any time on or after July 15, 2018. We are also entitled to redeem up to 35% of the aggregate principal amount of our 2021 Senior Notes before July 15, 2018, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107.875% of the principal amount of our 2021 Senior Notes being redeemed plus accrued and unpaid interest, if any, to the redemption date. In addition, prior to July 15, 2018, we may redeem some or all of our 2021 Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium. If we experience certain kinds of changes of control, holders of our 2021 Senior Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the notes, plus accrued and unpaid interest, if any, to the date of purchase.

Our 2021 Senior Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. Our 2021 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our 2021 Senior Notes) that guarantees our indebtedness under a credit facility. The notes are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the notes.

2024 Senior Notes

In August 2017, we closed a private offering of our 2024 Senior Notes that resulted in net proceeds of approximately $392.8 million. Our 2024 Senior Notes bear interest at an annual rate of 7.375%. Interest on our 2024 Senior Notes is payable on May 15 and November 15 of each year, and the first interest payment will be due on November 15, 2017. Our 2024 Senior Notes will mature on May 15, 2024.

We may, at our option, redeem all or a portion of our 2024 Senior Notes at any time on or after May 15, 2020 at the redemption prices set forth in the indenture governing the 2024 Senior Notes. We are also entitled to redeem up to 35% of the aggregate principal amount of our 2024 Senior Notes before May 15, 2020, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107.375% of the principal amount of our 2024 Senior Notes being redeemed plus accrued and unpaid interest, if any, to the redemption date. In addition, prior to May 15, 2020, we may redeem some or all of our 2024 Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium. If we experience certain kinds of changes of control, holders of our 2024 Senior Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the notes, plus accrued and unpaid interest, if any, to the date of purchase.

Our 2024 Senior Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. Our 2024 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our current subsidiaries and by certain future restricted subsidiaries that guarantees our indebtedness under a credit facility. The notes are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any of our future subsidiaries that do not guarantee the notes.

Series A Preferred Stock

The Company's Series A Preferred Stock (the "Series A Preferred Stock") are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). Each of the Series A Preferred Stock is convertible into shares of our common stock at the election of the Series A Preferred Holders at a conversion ratio per share of Series A Preferred Stock of 61.9195. Until the three-year anniversary of the closing of the IPO, we may elect to convert each share of Series A Preferred Stock at a conversion ratio of 61.9195, but only if the closing price of our common stock trades at or above a certain premium to our initial offering price, with such premiums decreasing with time. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock matures on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference. For more information, see the Company's Annual Report.

Critical Accounting Policies and Estimates

There were no changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2016.

Recent Accounting Pronouncements

In May 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-09, which provides clarification and reduces both (1) diversity in practice and (2) cost and complexity when applying the guidance in Topic 718 Compensation - Stock Compensation, to a change to the terms or conditions of a share-based payment award. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that reporting period. Early adoption is permitted for fiscal years beginning after December 15, 2016, including the interim reporting periods within that fiscal year. We are currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In February 2017, the FASB ASU No. 2017-05, which provides clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that reporting period. Early adoption is permitted for fiscal years beginning after December 15, 2016, including the interim reporting periods within that fiscal year. We are currently evaluating this new standard to determine the potential impact to our financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-04, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. We are currently evaluating this new standard to determine the potential impact to our financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, which clarifies the definition of a business when evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted for transactions for which the acquisition date occurs before the issuance date or effective date of the amendments, only when the transaction has not been reported in the financial statements that have been issued. We are currently evaluating this new standard and believe it could have a material impact to its financial statements and related disclosures.

In November 2016, the FASB issued ASU No. 2016-18, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment will be effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. We are currently evaluating this new standard to determine the potential impact to our financial statements and related disclosures.

In August 2016, the FASB issued ASU No. 2016-15, which addresses eight specific cash flow issues, including presentation of debt prepayments or debt extinguishment costs, with the objective of reducing the existing diversity in practice. In addition, in November 2016, the FASB issued ASU 2016-18, which requires that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including an adoption in an interim period, with a required retrospective application to each period presented. We are currently evaluating this new standard to determine the potential impact to our financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-06, which clarifies the requirements to assess whether an embedded put or call option is clearly and closely related to the debt host, solely in accordance with the four step decision sequence in FASB ASC Topic 815, Derivatives and Hedging, as amended by ASU 2016-06. This standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 and should be applied using a modified retrospective approach. Early adoption is permitted. We are currently evaluating the impact of adopting ASU 2016-06, however the standard is not expected to have a significant effect on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, which requires lessee recognition on the balance sheet of a right of use asset and a lease liability, initially measured at the present value of the lease payments. It further requires recognition in the income statement of a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight line basis. Finally, it requires classification of all cash payments within operating activities in the statements of cash flows. It is effective for fiscal years commencing after December 15, 2018 and early adoption is permitted. We are currently evaluating the impact this new standard will have on our financial statements and related disclosures. As part of our assessment work to-date, we formed an implementation work team, completed training of the new ASU's leasing guidance, and are developing a strategy for implementation.

In May 2014, the FASB issued ASU No. 2014-09, which establishes a comprehensive new revenue recognition model designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The ASU allows for the use of either the full or modified retrospective transition method. In August 2015, the FASB issued ASU No. 2015-14, which deferred ASU No. 2014-09 for one year, and is effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of reporting periods beginning after December 15, 2016. The FASB subsequent issued ASU 2016-08, ASU 2016-10, ASU 2016-11 and ASU 2016-12, and 2016-20, which provided additional implementation guidance. We are in the process of completing its initial review of contracts in each of its revenue streams and is developing accounting policies to address the provisions of this ASU. While we do not currently expect operating income (loss) to be materially impacted, we are currently analyzing whether total revenues and total expenses may change as a result of certain percentage of proceeds contracts. We will continue to evaluate the impact of this and other provisions of the ASU on its accounting policies, internal controls, and consolidated financial statements and related disclosures and has not finalized any estimates of the potential impacts. We will adopt this new standard on January 1, 2018, using the modified retrospective method with a cumulative adjustment to retained earnings.

Impact of Inflation/Deflation and Pricing

All of our transactions are denominated in U.S. dollars. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, as prices for oil and natural gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to decline commodity prices. Historically, field-level prices received for our oil and natural gas production have been volatile. During the years ended December 31, 2014 and 2015, commodity prices decreased, while during the year ended December 31, 2016, commodity prices increased and remained stable during the six months ended June 30, 2017. Changes in commodity prices impact our revenues, estimates of reserves, assessments of any impairment of oil and natural gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect our ability to raise capital, borrow money, and retain personnel.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil, natural gas and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGL has been volatile and unpredictable for several years and this volatility is expected to continue in the future. The prices we receive for our oil, natural gas and NGL production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil prices on our revenues, we have periodically entered into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations.

The following tables present our derivative positions related to crude oil and natural gas sales in effect as of June 30, 2017:

	For the Three Months Ended					
	September 30, 2017	December 31, 2017	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
NYMEX WTI[1] Crude Swaps:						
Notional volume (Bbl)	—	—	1,500,000	1,500,000	750,000	750,000
Weighted average fixed price ($/Bbl)	$ —	$ —	$ 50.70	$ 50.70	$ 53.88	$ 53.88
NYMEX WTI[1] Crude Sold Calls:						
Notional volume (Bbl)	2,250,000	2,250,000	850,000	750,000	450,000	450,000
Weighted average fixed price ($/Bbl)	$ 56.28	$ 56.51	$ 60.31	$ 61.02	$ 60.54	$ 60.54
NYMEX WTI[1] Crude Sold Puts:						
Notional volume (Bbl)	2,075,000	2,175,000	2,100,000	2,100,000	1,200,000	1,200,000
Weighted average purchased put price ($/Bbl)	$ 38.45	$ 38.38	$ 39.43	$ 39.43	$ 40.00	$ 40.00
NYMEX WTI[1] Crude Purchased Puts:						
Notional volume (Bbl)	2,250,000	2,250,000	750,000	750,000	450,000	450,000
Weighted average purchased put price ($/Bbl)	$ 47.84	$ 48.04	$ 50.80	$ 50.80	$ 50.00	$ 50.00
NYMEX HH[2] Natural Gas Swaps:						
Notional volume (MMBtu)	7,420,000	7,420,000	9,900,000	8,700,000	8,100,000	8,100,000
Weighted average fixed price ($/MMBtu)	$ 3.06	$ 3.06	$ 3.30	$ 3.03	$ 3.03	$ 3.03
NYMEX HH[2] Natural Gas Purchased Puts:						
Notional volume (MMBtu)	—	—	600,000	600,000	600,000	600,000
Weighted average purchased put price ($/MMBtu)	$ —	$ —	$ 3.00	$ 3.00	$ 3.00	$ 3.00
NYMEX HH[2] Natural Gas Sold Calls:						
Notional volume (MMBtu)	—	—	600,000	600,000	600,000	600,000
Weighted average sold call price ($/MMBtu)	$ —	$ —	$ 3.15	$ 3.15	$ 3.15	$ 3.15
CIG[3] Basis Gas Swaps:						
Notional volume (MMBtu)	3,680,000	5,215,000	6,300,000	—	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.38)	$ (0.31)	$ (0.31)	$ —	$ —	$ —

(1) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange
(2) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange
(3) CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) settlement price.

As of June 30, 2017, the fair market value of our oil derivative contracts was a net asset of $27.2 million. Based on our open oil derivative positions at June 30, 2017, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $36.5 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $35.0 million. As of June 30, 2017, the fair market value of our natural gas derivative contracts was a net asset of $3.5 million. Based upon our open commodity derivative positions at June 30, 2017, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by approximately $24.1 million, while a 10% decrease in the NYMEX Henry Hub price would increase our net natural gas derivate asset by approximately $15.0 million. Please see "—How We Evaluate Our Operations—Derivative Arrangements."

Counterparty and Customer Credit Risk

Our cash and cash equivalents are exposed to concentrations of credit risk. We manage and control this risk by investing these funds with major financial institutions. We often have balances in excess of the federally insured limits.

We sell oil, natural gas and NGL to various types of customers, including pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside of our control, none of which can be predicted with certainty. For the six months ended June 30, 2017, we had certain major customers that exceeded 10% of total oil, natural gas and NGL revenues. We do not believe the loss of any single purchaser would materially impact our operating results because oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

At June 30, 2017, we had commodity derivative contracts with six counterparties. We do not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Additionally, we use master netting agreements to minimize credit risk exposure. The creditworthiness of our counterparties is subject to periodic review. Three of the six counterparties to the derivative instruments are highly rated entities with corporate ratings at A3 classifications or above by Moody's. The other three counterparties had a corporate rating of Baa1 by Moody's. For the three and six months ended June 30, 2017 and 2016, we did not incur any losses with respect to counterparty contracts. None of our existing derivative instrument contracts contains credit risk related contingent features.

Interest Rate Risk

At June 30, 2017, we had no variable rate debt outstanding. Assuming we had the full amount of variable-rate debt outstanding available to us at June 30, 2017 of $475.0 million, the impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $4.8 million. We may begin entering into interest rate swap arrangements on a portion of our outstanding debt to mitigate the risk of fluctuations in LIBOR if we have variable-rate debt outstanding in the future. Please see "—Liquidity and Capital Resources—Debt Arrangements."

Off-Balance Sheet Arrangements

As of June 30, 2017, we did not have any off-balance sheet arrangements other than operating leases, contractual commitments for drilling rigs, gathering commitments, and acquisitions of undeveloped leasehold acreage. Additionally, our oil marketer is subject to a firm transportation agreement with a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. Please see *Note 11 – Commitments and Contingencies* in Part 1, Item 1 of this Quarterly Report.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2017.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended June 30, 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in *Note 11 – Commitments and Contingencies*, to our condensed consolidated financial statements included elsewhere in this report.

We are currently in discussions with the Colorado Department of Public Health and Environment (“CDPHE”) regarding a Compliance Advisory issued to us in July 2015, which alleged air quality violations at three of our facilities regarding leakages of volatile organic compounds from storage tanks, all of which were promptly addressed. We continue to work with the CDPHE on its investigation into our facilities and it intends to seek a field-wide administrative settlement of these issues. At this time we cannot predict the outcome of this matter or the remediation or compliance costs that this matter may impose upon us.

From time to time, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. As of the filing date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows.

ITEM 1A. RISK FACTORS

Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under Item 1A “Risk Factors”, included in our Annual Report. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

(a) Exhibits:

The exhibits listed on the accompanying Exhibit Index are filed, furnished or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: August 9, 2017.

Extraction Oil & Gas, Inc.

By: /S/ MARK A. ERICKSON

Mark A. Erickson

Chairman and Chief Executive Officer

(principal executive officer)

By: /S/ RUSSELL T. KELLEY, JR.

Russell T. Kelley, Jr.

Chief Financial Officer

(principal financial officer)

INDEX TO EXHIBITS

Exhibit Number	Description
3.1	Certificate of Incorporation of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
3.2	Certificate of Designations of Series A Preferred Stock of Extraction Oil & Gas, Inc., filed with the Secretary of State of the State of Delaware on October 17, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
3.3	Bylaws of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
4.1	Indenture, dated August 1, 2017, by and among Extraction Oil & Gas, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on August 3, 2017).
*4.2	Second Supplemental Indenture, dated December 22, 2016 by and among Extraction Oil & Gas, Inc., Extraction Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.
*4.3	Third Supplemental Indenture, dated June 29, 2017 by and among Extraction Oil & Gas, Inc., Extraction Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.
*10.1	Amendment No. 12 to the Credit Agreement, dated as of May 5, 2017, by and among Extraction Oil & Gas, Inc., as borrower, certain subsidiaries of the Company, as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto.
*31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
**32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	Interactive Data Files

* Filed herewith.

** Furnished herewith.

Exhibit 4.2

SECOND SUPPLEMENTAL INDENTURE

SECOND SUPPLEMENTAL INDENTURE (this "Supplemental Indenture"), dated as of December 22, 2016, among Bison Exploration, LLC (the "Guaranteeing Subsidiary"), a subsidiary of Extraction Oil & Gas, Inc., a Delaware corporation and successor to Extraction Oil & Gas Holdings, LLC (the "Company"), the Company, Extraction Finance Corp., a Delaware corporation ("Finance Corp." and together with the Company, the "Issuers" and individually an "Issuer"), the other Guarantors (as defined in the Indenture referred to herein) and Wells Fargo Bank, National Association, as trustee under the Indenture referred to below (the "Trustee").

WITNESSETH

WHEREAS, the Issuers have heretofore executed and delivered to the Trustee an indenture (the "Indenture"), dated as of July 18, 2016 providing for the issuance of 7.875% Senior Notes due July 15, 2021 (the "Notes");

WHEREAS, the Indenture provides that under certain circumstances the Guaranteeing Subsidiary shall execute and deliver to the Trustee a supplemental indenture pursuant to which the Guaranteeing Subsidiary shall unconditionally Guarantee all of the Issuers' Obligations under the Notes and the Indenture on the terms and conditions set forth herein (the "Note Guarantee"); and

WHEREAS, pursuant to Section 9.01 of the Indenture, the Trustee is authorized to execute and deliver this Supplemental Indenture.

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt of which is hereby acknowledged, the Guaranteeing Subsidiary, the other Guarantors, the Issuers and the Trustee mutually covenant and agree for the equal and ratable benefit of the Holders of the Notes as follows:

1. CAPITALIZED TERMS. Capitalized terms used herein without definition shall have the meanings assigned to them in the Indenture.

2. AGREEMENT TO GUARANTEE. The Guaranteeing Subsidiary hereby agrees to provide an unconditional Guarantee on the terms and subject to the conditions set forth in the Note Guarantee and in the Indenture including but not limited to Article 10 thereof.

3. NO RECOURSE AGAINST OTHERS. No director, manager, officer, member, partner, employee, incorporator or unitholder or other owner of Capital Stock of the Issuers or any Guarantor, as such, will have any liability for any obligations of the Issuers or the Guarantors under the Notes, the Indenture or the Note Guarantees or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each Holder of Notes by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes.

4. NEW YORK LAW TO GOVERN. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE THIS SUPPLEMENTAL INDENTURE.

5. COUNTERPARTS. The parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of them together represent the same agreement.

6. EFFECT OF HEADINGS. The Section headings herein are for convenience only and shall not affect the construction hereof.

7. THE TRUSTEE. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made solely by the Guaranteeing Subsidiary, the other Guarantors and the Issuers.

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed and attested, all as of the date first above written.

Dated: December 22, 2016

BISON EXPLORATION, LLC

By: /s/ Russel T. Kelley, Jr.
Name: Russell T. Kelley, Jr.
Title: Chief Financial Officer

EXTRACTION OIL & GAS, INC.

By: /s/ Russel T. Kelley, Jr.
Name: Russell T. Kelley, Jr.
Title: Chief Financial Officer

EXTRACTION FINANCE CORP.

By: /s/ Russel T. Kelley, Jr.
Name: Russell T. Kelley, Jr.
Title: Chief Financial Officer

ELEVATION MIDSTREAM

By: /s/ Russel T. Kelley, Jr.
Name: Russell T. Kelley, Jr.
Title: Chief Financial Officer

XTR MIDSTREAM, LLC

By: /s/ Russel T. Kelley, Jr.
Name: Russell T. Kelley, Jr.
Title: Chief Financial Officer

7N, LLC

By: /s/ Russel T. Kelley, Jr.
Name: Russell T. Kelley, Jr.
Title: Chief Financial Officer

MOUNTAINTOP MINERALS, LLC

By:	/s/ Russel T. Kelley, Jr.
Name:	Russell T. Kelley, Jr.
Title:	Chief Financial Officer

8 NORTH, LLC

By:	/s/ Russel T. Kelley, Jr.
Name:	Russell T. Kelley, Jr.
Title:	Chief Financial Officer

XOG SERVICES, INC.

By:	/s/ Russel T. Kelley, Jr.
Name:	Russell T. Kelley, Jr.
Title:	Chief Financial Officer

XOG SERVICES, LLC

By:	/s/ Russel T. Kelley, Jr.
Name:	Russell T. Kelley, Jr.
Title:	Chief Financial Officer

WELLS FARGO BANK, NATIONAL ASSOCIATION
As Trustee

By: /s/ Authorized Signatory
Authorized Signatory

[SIGNATURE PAGE TO SUPPLEMENTAL INDENTURE]

Exhibit 4.3

THIRD SUPPLEMENTAL INDENTURE

THIRD SUPPLEMENTAL INDENTURE (this “Supplemental Indenture”), dated as of June 29, 2017, among Table Mountain Resources, LLC (the “Guaranteeing Subsidiary”), a subsidiary of Extraction Oil & Gas, Inc., a Delaware corporation (the “Company”), the Company, Extraction Finance Corp., a Delaware corporation (“Finance Corp.” and together with the Company, the “Issuers” and individually an “Issuer”), the other Guarantors (as defined in the Indenture referred to herein) and Wells Fargo Bank, National Association, as trustee under the Indenture referred to below (the “Trustee”).

WITNESSETH

WHEREAS, the Issuers have heretofore executed and delivered to the Trustee an indenture (the “Indenture”), dated as of July 18, 2016 providing for the issuance of 7.875% Senior Notes due July 15, 2021 (the “Notes”);

WHEREAS, the Indenture provides that under certain circumstances the Guaranteeing Subsidiary shall execute and deliver to the Trustee a supplemental indenture pursuant to which the Guaranteeing Subsidiary shall unconditionally Guarantee all of the Issuers’ Obligations under the Notes and the Indenture on the terms and conditions set forth herein (the “Note Guarantee”); and

WHEREAS, pursuant to Section 9.01 of the Indenture, the Trustee is authorized to execute and deliver this Supplemental Indenture.

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt of which is hereby acknowledged, the Guaranteeing Subsidiary, the other Guarantors, the Issuers and the Trustee mutually covenant and agree for the equal and ratable benefit of the Holders of the Notes as follows:

1. CAPITALIZED TERMS. Capitalized terms used herein without definition shall have the meanings assigned to them in the Indenture.

2. AGREEMENT TO GUARANTEE. The Guaranteeing Subsidiary hereby agrees to provide an unconditional Guarantee on the terms and subject to the conditions set forth in the Note Guarantee and in the Indenture including but not limited to Article 10 thereof.

3. NO RECOURSE AGAINST OTHERS. No director, manager, officer, member, partner, employee, incorporator or unitholder or other owner of Capital Stock of the Issuers or any Guarantor, as such, will have any liability for any obligations of the Issuers or the Guarantors under the Notes, the Indenture or the Note Guarantees or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each Holder of Notes by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes.

4. NEW YORK LAW TO GOVERN. THE LAW OF THE STATE OF NEW YORK SHALL GOVERN AND BE USED TO CONSTRUE THIS SUPPLEMENTAL INDENTURE.

5. COUNTERPARTS. The parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of them together represent the same agreement.

6. EFFECT OF HEADINGS. The Section headings herein are for convenience only and shall not affect the construction hereof.

7. THE TRUSTEE. The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made solely by the Guaranteeing Subsidiary, the other Guarantors and the Issuers.

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed and attested, all as of the date first above written.

Guaranteeing Subsidiary:

TABLE MOUNTAIN RESOURCES, LLC

By: /s/ Eric J. Christ
Name: Eric J. Christ
Title: Vice President, General Counsel and Corporate Secretary

Issuers:

EXTRACTION OIL & GAS, INC.

By: /s/ Eric J. Christ
Name: Eric J. Christ
Title: Vice President, General Counsel and Corporate Secretary

EXTRACTION FINANCE CORP.

By: /s/ Eric J. Christ
Name: Eric J. Christ
Title: Vice President, General Counsel and Corporate Secretary

Existing Subsidiary Guarantors:

ELEVATION MIDSTREAM, LLC

By: /s/ Eric J. Christ
Name: Eric J. Christ
Title: Vice President, General Counsel and Corporate Secretary

XTR MIDSTREAM, LLC

By:	/s/ Eric J. Christ
Name:	Eric J. Christ
Title:	Vice President, General Counsel and Corporate Secretary

7N, LLC

By:	/s/ Eric J. Christ
Name:	Eric J. Christ
Title:	Vice President, General Counsel and Corporate Secretary

MOUNTAINTOP MINERALS, LLC

By:	/s/ Eric J. Christ
Name:	Eric J. Christ
Title:	Vice President, General Counsel and Corporate Secretary

8 NORTH, LLC

By:	/s/ Eric J. Christ
Name:	Eric J. Christ
Title:	Vice President, General Counsel and Corporate Secretary

XOG SERVICES, INC.

By:	/s/ Eric J. Christ
Name:	Eric J. Christ
Title:	Vice President, General Counsel and Corporate Secretary

XOG SERVICES, LLC

By:	/s/ Eric J. Christ
Name:	Eric J. Christ
Title:	Vice President, General Counsel and Corporate Secretary

BISON EXPLORATION, LLC

By:	/s/ Eric J. Christ
Name:	Eric J. Christ
Title:	Vice President, General Counsel and Corporate Secretary

[SIGNATURE PAGE TO SUPPLEMENTAL INDENTURE]

WELLS FARGO BANK, NATIONAL ASSOCIATION
As Trustee

By: /s/ Authorized Signatory
Authorized Signatory

[SIGNATURE PAGE TO SUPPLEMENTAL INDENTURE]

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Mark A. Erickson, certify that:

1. I have reviewed this quarterly report on Form 10-Q (this "report") of Extraction Oil & Gas, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 9, 2017

/S/ MARK A. ERICKSON

Mark A. Erickson
Chief Executive Officer and Chairman
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Russell T. Kelley, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q (this “report”) of Extraction Oil & Gas, Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 9, 2017

/S/ RUSSELL T. KELLEY, JR.

Russell T. Kelley, Jr.
Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350**

In connection with the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017 of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark A. Erickson, Chief Executive Officer and Chairman of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 9, 2017

/S/ MARK A. ERICKSON

Mark A. Erickson
Chief Executive Officer and Chairman
(Principal Executive Officer)

Exhibit 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017 of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Russell T. Kelley, Jr., Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 9, 2017

/S/ RUSSELL T. KELLEY, JR.

Russell T. Kelley, Jr.
Chief Financial Officer
(Principal Financial Officer)