

CONTANGO OIL & GAS CO
Form 10-Q
August 03, 2017
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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 001-16317

CONTANGO OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

DELAWARE

95-4079863

(State or other jurisdiction of
incorporation or organization)

(IRS Employer
Identification No.)

717 TEXAS AVENUE, SUITE 2900

HOUSTON, TEXAS

77002

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(Address of principal executive offices) (Zip Code)

(713) 236-7400

(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 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 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

Smaller reporting company

Emerging growth company

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.

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

The total number of shares of common stock, par value \$0.04 per share, outstanding as of July 31, 2017 was 25,609,830.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY REPORT ON FORM 10-Q

FOR THE SIX MONTHS ENDED JUNE 30, 2017

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All references in this Quarterly Report on Form 10-Q to the "Company", "Contango", "we", "us" or "our" are to Contango Oil Gas Company and its subsidiaries.

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Item 1. Consolidated Financial Statements

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except shares)

	June 30, 2017	December 31, 2016
	(unaudited)	
CURRENT ASSETS:		
Cash and cash equivalents	\$ —	\$ —
Accounts receivable, net	11,621	16,727
Prepaid expenses	2,189	1,787
Current derivative asset	1,233	—
Inventory	—	540
Total current assets	15,043	19,054
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,208,492	1,188,065
Unproved properties	40,818	38,338
Other property and equipment	1,268	1,265
Accumulated depreciation, depletion and amortization	(908,243)	(887,286)
Total property, plant and equipment, net	342,335	340,382
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	17,717	15,767
Other	1,073	1,311
Total other non-current assets	18,790	17,078
TOTAL ASSETS	\$ 376,168	\$ 376,514
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	\$ 45,699	\$ 55,135
Current derivative liability	351	3,446
Current asset retirement obligations	5,789	4,308
Total current liabilities	51,839	62,889
NON-CURRENT LIABILITIES:		
Long-term debt	71,316	54,354
Asset retirement obligations	18,592	22,618
Other long term liabilities	248	248
Total non-current liabilities	90,156	77,220
Total liabilities	141,995	140,109
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
SHAREHOLDERS' EQUITY:		
	1,226	1,211

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Common stock, \$0.04 par value, 50 million shares authorized, 30,949,898 shares issued and 25,607,530 shares outstanding at June 30, 2017, 30,557,987 shares issued and 25,238,600 shares outstanding at December 31, 2016		
Additional paid-in capital	299,502	296,439
Treasury shares at cost (5,342,368 shares at June 30, 2017 and 5,319,387 shares at December 31, 2016)	(128,482)	(128,321)
Retained earnings	61,927	67,076
Total shareholders' equity	234,173	236,405
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 376,168	\$ 376,514

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(unaudited)		(unaudited)	
REVENUES:				
Oil and condensate sales	\$ 6,483	\$ 6,971	\$ 12,025	\$ 12,218
Natural gas sales	11,135	9,337	22,275	19,272
Natural gas liquids sales	2,658	3,054	5,400	5,454
Total revenues	20,276	19,362	39,700	36,944
EXPENSES:				
Operating expenses	6,329	7,020	13,162	14,624
Exploration expenses	284	324	375	644
Depreciation, depletion and amortization	12,714	17,875	24,485	34,420
Impairment and abandonment of oil and gas properties	1,401	1,252	1,431	3,103
General and administrative expenses	5,833	5,384	12,429	11,286
Total expenses	26,561	31,855	51,882	64,077
OTHER INCOME (EXPENSE):				
Gain from investment in affiliates, net of income taxes	166	1,295	1,950	1,335
Gain (loss) from sale of assets	(420)	—	2,520	—
Interest expense	(925)	(1,178)	(1,684)	(2,056)
Gain (loss) on derivatives, net	1,487	(4,381)	4,583	(177)
Other income (expense)	61	(270)	(27)	(310)
Total other income (expense)	369	(4,534)	7,342	(1,208)
NET LOSS BEFORE INCOME TAXES	(5,916)	(17,027)	(4,840)	(28,341)
Income tax provision	(118)	(269)	(309)	(359)
NET LOSS	\$ (6,034)	\$ (17,296)	\$ (5,149)	\$ (28,700)
NET LOSS PER SHARE:				
Basic	\$ (0.24)	\$ (0.90)	\$ (0.21)	\$ (1.50)
Diluted	\$ (0.24)	\$ (0.90)	\$ (0.21)	\$ (1.50)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	24,671	19,121	24,639	19,100
Diluted	24,671	19,121	24,639	19,100

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Six Months Ended June 30,	
	2017	2016
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	\$ (5,149)	\$ (28,700)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	24,485	34,420
Impairment of natural gas and oil properties	1,400	3,012
Exploration recovery	(232)	(58)
Gain on sale of assets	(2,520)	—
Gain from investment in affiliates	(1,950)	(1,335)
Stock-based compensation	3,078	2,978
Unrealized loss (gain) on derivative instruments	(4,327)	3,932
Changes in operating assets and liabilities:		
Decrease in accounts receivable & other receivables	5,044	5,346
Increase in prepaids	(402)	(1,179)
Decrease in inventory	123	—
Decrease in accounts payable & advances from joint owners	(41)	(8,651)
Increase (decrease) in other accrued liabilities	(1,260)	705
Decrease (increase) in income taxes receivable, net	—	2,868
Increase (decrease) in income taxes payable, net	(201)	(243)
Other	61	(18)
Net cash provided by operating activities	\$ 18,109	\$ 13,077
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	\$ (35,553)	\$ (7,383)
Additions to furniture & equipment	(39)	—
Sale of furniture & equipment	12	—
Sale of oil & gas properties	670	—
Net cash used in investing activities	\$ (34,910)	\$ (7,383)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	\$ 113,506	\$ 79,526
Repayments under credit facility	(96,544)	(83,994)
Purchase of treasury stock	(161)	(230)
Debt issuance costs	—	(996)
Net cash provided by (used in) financing activities	\$ 16,801	\$ (5,694)
NET CHANGE IN CASH AND CASH EQUIVALENTS	\$ —	\$ —

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CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	\$ —	\$ —

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(in thousands, except number of shares)

	Common Stock Shares (unaudited)	Amount	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
Balance at December 31, 2016	25,238,600	\$ 1,211	\$ 296,439	\$ (128,321)	\$ 67,076	\$ 236,405
Treasury shares at cost	(22,981)	—	—	(161)	—	(161)
Restricted shares activity	391,911	15	(15)	—	—	—
Stock-based compensation	—	—	3,078	—	—	3,078
Net income	—	—	—	—	(5,149)	(5,149)
Balance at June 30, 2017	25,607,530	\$ 1,226	\$ 299,502	\$ (128,482)	\$ 61,927	\$ 234,173

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Organization and Business

Contango Oil & Gas Company (collectively with its subsidiaries, “Contango” or the “Company”) is a Houston, Texas based, independent oil and natural gas company. The Company’s business is to maximize production and cash flow from its offshore properties in the shallow waters of the Gulf of Mexico (“GOM”) and onshore properties in Texas and Wyoming and to use that cash flow to explore, develop, exploit, produce and acquire crude oil and natural gas properties in the Texas and Rocky Mountain regions of the United States.

The following table lists the Company’s primary producing areas as of June 30, 2017:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Zavala and Dimmit counties, Texas	Buda / Austin Chalk
Weston County, Wyoming	Muddy Sandstone
Pecos County, Texas	Southern Delaware Basin (Wolfcamp)
Texas Gulf Coast	Conventional and unconventional formations
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC (“Exaro”). Production associated with this investment is not included in the Company’s reported production results for the three and six months ended June 30, 2017.

In July 2016, the Company purchased approximately 12,100 gross operated undeveloped acres (5,000 net acres) in the Southern Delaware Basin in Pecos County, Texas (the “Acquisition”), which it began drilling during the fourth quarter of 2016, and as of June 30, 2017, had increased its acreage to approximately 13,500 gross operated acres (6,700 net).

The Company’s remaining 2017 capital program will focus on the development of its Southern Delaware Basin acreage, while preserving its healthy financial position. Additionally, the Company will continue to identify opportunities for cost efficiencies in all areas of its operations, maintain core leases and continue to identify new resource potential opportunities internally and, where appropriate, through acquisition. The Company will

continuously monitor the commodity price environment, including its stability and forecast, and, if warranted, make adjustments to its strategy as the year progresses.

2. Summary of Significant Accounting Policies

The accounting policies followed by the Company are set forth in the notes to the Company's audited consolidated financial statements included in its Annual Report on Form 10-K for the year ended December 31, 2016 (the "2016 Form 10-K") filed with the Securities and Exchange Commission ("SEC"). Please refer to the notes to the financial statements included in the 2016 Form 10-K for additional details of the Company's financial condition, results of operations and cash flows. No material items included in those notes have changed except as a result of normal transactions in the interim or as disclosed within this report.

Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information, pursuant to the rules and regulations of the SEC, including instructions to Quarterly Reports on Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements. In the opinion of management, all adjustments considered necessary for a fair statement of the unaudited consolidated financial statements have been included. All such adjustments are of a normal recurring nature. The consolidated financial statements should be read in conjunction with the 2016 Form 10-K. The consolidated results of operations for the six months ended June 30, 2017 are not necessarily indicative of the results that may be expected for the year ending December 31, 2017.

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The Company's consolidated financial statements include the accounts of Contango Oil & Gas Company and its subsidiaries, after elimination of all material intercompany balances and transactions. All wholly owned subsidiaries are consolidated. The investment in Exaro by our wholly owned subsidiary, Contaro Company ("Contaro") is accounted for using the equity method of accounting, and therefore, the Company does not include its share of individual operating results, reserves or production in those reported for the Company's consolidated results.

Oil and Gas Properties - Successful Efforts

Our application of the successful efforts method of accounting for our natural gas and oil exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Impairment of Long-Lived Assets

Pursuant to GAAP, when circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted cash flows based on the Company's estimate of future reserves, natural gas and oil prices, operating costs and production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair value. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. The Company recognized no impairment of proved properties for the three and six months ended June 30, 2017. No impairment of proved properties was recognized for the three months ended June 30, 2016, and the Company recognized approximately \$0.7 million impairment of proved properties for the six months ended June 30, 2016, substantially all of which was directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. The Company recognized \$1.4 million in impairment expense related to the partial impairment of two unused offshore platforms for the three and six months ended June 30, 2017. The Company recognized impairment expense of approximately \$1.1 million and approximately \$2.3 million for the three and six months ended June 30, 2016, respectively, related to partial impairment of certain unproved properties due primarily to the sustained low commodity price environment and expiring leases, substantially all of which was related to unproved lease cost amortization of the properties in Fayette and Gonzales counties Texas.

Net Income (Loss) Per Common Share

Basic net income (loss) per common share is computed by dividing the net income (loss) attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income (loss) per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. Potential dilutive securities, including unexercised stock options, Performance Stock Units ("PSUs") and unvested restricted stock, have not been considered when their effect would be antidilutive. For the three and six months ended June 30, 2017, 97,319 stock options, 863,317 restricted shares and 405,455 Performance Stock Units were excluded from dilutive shares, as they were anti-dilutive. For the three and six

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months ended June 30, 2016, 114,804 stock options and 485,972 restricted shares were excluded from dilutive shares, as they were anti-dilutive.

Subsidiary Guarantees

Contango Oil & Gas Company, as the parent company (the “Parent Company”), has filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities that the Parent Company may issue from time to time. Any such debt securities would likely be guaranteed on a full and unconditional basis by each of the Company’s current subsidiaries and any future subsidiaries specified in any future prospectus supplement (each a “Subsidiary Guarantor”). Each of the Subsidiary Guarantors is wholly owned by the Parent Company, either directly or indirectly. The Parent Company has no assets or operations independent of the Subsidiary Guarantors, and there are no significant restrictions upon the ability of the Subsidiary Guarantors to distribute funds to the Parent Company. The Parent Company has one wholly owned subsidiary that is inactive and not a Subsidiary Guarantor. Finally, the Parent Company’s wholly owned subsidiaries do not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by such subsidiary without the consent of a third party.

Recent Accounting Pronouncements

In January 2017, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2017-01: Business Combinations (Topic 805) Clarifying the Definition of a Business (ASU 201701). The amendments in this update are intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. Public business entities should apply the amendments in this update to annual periods beginning after December 15, 2017, including interim periods within those periods. The amendments in this update should be applied prospectively on or after the effective date. No disclosures are required at transition. The provisions of this accounting update are not expected to have a material impact on the Company’s financial position or results of operations.

In August 2016, the FASB issued ASU No. 2016-15: Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments. The main objective of this update is to reduce the diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash Flows, and other Topics. This update addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice. The eight cash flow updates relate to the following issues: 1) debt prepayment or debt extinguishment costs; 2) settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; 3) contingent consideration payments made after a business combination; 4) proceeds from the settlement of insurance claims; 5) proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies;

6) distributions received from equity method investees; 7) beneficial interest in securitization transactions; and 8) separately identifiable cash flows and application of the predominance principle. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The provisions of this accounting update are not expected to have a material impact on the Company's presentation of cash flows.

In February 2016, the FASB issued ASU No. 2016-02: Leases (Topic 842) (ASU 2016-02). The main objective of ASU 2016-02 is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires lessees to recognize assets and liabilities arising from leases on the balance sheet. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. For public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early application is permitted. The Company will continue to assess the impact this may have on its financial position, results of operations, and cash flows.

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In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606),” which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Several additional standards related to revenue recognition have been issued that amend the original standard, with most providing additional clarification.

In August 2015, the FASB issued ASU No. 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date,” which deferred the effective date of ASU 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. The Company is currently determining the impact of the new revenue recognition standard on its contracts. The Company’s revenue contracts are primarily normal purchase/sale contracts and as such, the Company does not expect that the new revenue recognition standard will have a material impact on the Company’s financial statements upon adoption. The Company expects to use the modified retrospective method to adopt the standard, meaning the cumulative effect of initially applying the standard will be recognized at the date of the adoption of the standard.

3. Acquisitions and Dispositions

In the July 2016 Acquisition, the Company purchased one-half of the seller’s interest in approximately 12,100 gross undeveloped acres (approximately 5,000 net acres) in the Southern Delaware Basin of Texas for up to \$25 million. The purchase price was comprised of \$10 million in cash paid on July 26, 2016, plus \$10 million in carried well costs expected to be paid over the period of drilling and completion of the first six wells. As of June 30, 2017, the Company had paid \$9.1 million of these carried well costs. Additionally, contingent upon success, \$5 million in spud bonuses is to be paid ratably over the next 14 wells drilled, which increases the total consideration to \$25 million. As of June 30, 2017, the Company had increased its acreage to approximately 13,500 gross operated acres (6,700 net).

On December 30, 2016, all of the Company’s non-core Colorado assets were sold to an independent oil and gas company for an aggregate purchase price of \$5.0 million, subject to normal post-closing adjustments. The properties consisted of the Company’s approximately 16,000 gross (11,200 net) acres primarily in Adams and Weld counties, Colorado and associated producing vertical wells.

Effective February 1, 2017, the Company sold to a third party all of its assets in the Bob West North area and its operated assets in the Escobas area, both located in Southeast Texas, for a cash purchase price of \$650,000. The Company recorded a net gain of \$2.9 million after removal of the asset retirement obligations associated with the sold properties.

4. Fair Value Measurements

Pursuant to Accounting Standards Codification 820, Fair Value Measurements and Disclosures (ASC 820), the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value as of June 30, 2017. As required by ASC 820, a financial instrument's

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level within the fair value hierarchy is 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 fair value assets and liabilities and their placement within the fair value hierarchy levels. There have been no transfers between Level 1, Level 2 or Level 3.

Fair value information for financial assets and liabilities was as follows as of June 30, 2017 (in thousands):

	Total Carrying Value	Fair Value Measurements Using		
		Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts - assets	\$ 1,233	\$ —	\$ 1,233	\$ —
Commodity price contracts - liabilities	\$ (351)	\$ —	\$ (351)	\$ —

Derivatives listed above are recorded in "Current and long-term derivative asset or liability" on the Company's consolidated balance sheet and include swaps and costless collars that are carried at fair value. The Company records the net change in the fair value of these positions in "Gain (loss) on derivatives, net" in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. See Note 5 - "Derivative Instruments" for additional discussion of derivatives.

As of June 30, 2017, the Company's derivative contracts were with certain members of its bank group which are major financial institutions with investment grade credit ratings which are believed to have minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance.

Estimates of the fair value of financial instruments are made in accordance with the requirements of ASC 825, Financial Instruments. The estimated fair value amounts are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's credit facility with the Royal Bank of Canada and other lenders (the "RBC Credit Facility") approximates carrying value because the facility interest rate approximates current market rates and is reset at least every six months. See Note 9 - "Long-Term Debt" for further information.

Impairments

Contango tests proved oil and natural gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. The Company estimates the undiscounted future cash flows expected in connection with the oil and gas properties on a field by field basis and compares such future cash flows to the unamortized capitalized costs of the properties. If the estimated future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. Because these significant fair value inputs are typically not observable, impairments of long-lived assets are classified as a Level 3 fair value measure.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period.

Asset Retirement Obligations

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. The factors used to determine fair value include, but are not limited to, estimated future plugging and abandonment costs and expected lives of the related reserves.

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5. Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk. Derivative contracts are typically utilized to hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company typically hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. The Company believes that these derivative arrangements, although not free of risk, allow it to achieve a more predictable cash flow and to reduce exposure to commodity price fluctuations. However, derivative arrangements limit the benefit of increases in the prices of crude oil, natural gas and natural gas liquids sales. Moreover, because its derivative arrangements apply only to a portion of its production, the Company's strategy provides only partial protection against declines in commodity prices. Such arrangements may expose the Company to risk of financial loss in certain circumstances. The Company continuously reevaluates its hedging programs in light of changes in production, market conditions and commodity price forecasts.

As of June 30, 2017, the Company's natural gas and oil derivative positions consisted of "swaps" and "costless collars". Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. A costless collar consists of a purchased put option and a sold call option, which establishes a minimum and maximum price, respectively, that the Company will receive for the volumes under the contract.

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. The Company does not post collateral, nor is it exposed to potential margin calls, under any of these contracts as they are secured under the RBC Credit Facility. See Note 9 - "Long-Term Debt" for further information regarding the RBC Credit Facility.

The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in "Gain (loss) on derivatives, net" on the consolidated statements of operations.

The following derivative instruments were in place at June 30, 2017 (fair value in thousands):

Commodity	Period	Derivative	Volume/Month	Price/Unit (1)	Fair Value
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Natural Gas	July 2017	Collar	400,000 MMBtu	\$ 2.65 - 3.00	(21)
Natural Gas	Aug 2017 - Oct 2017	Collar	200,000 MMBtu	\$ 2.65 - 3.00	(89)
Natural Gas	Nov 2017 - Dec 2017	Collar	400,000 MMBtu	\$ 2.65 - 3.00	(241)
Natural Gas	July 2017	Swap	300,000 MMBtu	\$ 3.51	131
Natural Gas	Aug 2017 - Oct 2017	Swap	70,000 MMBtu	\$ 3.51	97
Natural Gas	Nov 2017 - Dec 2017	Swap	300,000 MMBtu	\$ 3.51	187
Oil	July 2017	Swap	9,000 Bbls	\$ 53.95	70
Oil	Aug 2017 - Oct 2017	Swap	6,000 Bbls	\$ 53.95	132
Oil	Nov 2017 - Dec 2017	Swap	8,000 Bbls	\$ 53.95	106
Oil	July - Dec 2017	Swap	9,000 Bbls	\$ 56.20	510
Total net fair value of derivative instruments					\$ 882

(1) Commodity price derivatives are based on Henry Hub NYMEX natural gas prices and West Texas Intermediate oil prices, as applicable.

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The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of June 30, 2017 (in thousands):

	Gross	Netting (1)	Total
Assets	\$ 1,233	\$ —	\$ 1,233
Liabilities	\$ (351)	\$ —	\$ (351)

(1) Represents counterparty netting under agreements governing such derivatives.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2016 (in thousands):

	Gross	Netting (1)	Total
Assets	\$ —	\$ —	\$ —
Liabilities	\$ (3,446)	\$ —	\$ (3,446)

(1) Represents counterparty netting under agreements governing such derivatives.

The following table summarizes the effect of derivative contracts on the consolidated statements of operations for the three and six months ended June 30, 2017 and 2016 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Crude oil contracts	\$ 367	\$ —	\$ 537	\$ —
Natural gas contracts	68	2,248	(281)	3,755
Realized gain	\$ 435	\$ 2,248	\$ 256	\$ 3,755
Crude oil contracts	\$ 293	\$ —	\$ 817	\$ —
Natural gas contracts	759	(6,629)	3,510	(3,932)
Unrealized gain (loss)	\$ 1,052	\$ (6,629)	\$ 4,327	\$ (3,932)
Gain (loss) on derivatives, net	\$ 1,487	\$ (4,381)	\$ 4,583	\$ (177)

6. Stock-Based Compensation

Stock Options

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the six months ended June 30, 2017 and 2016, there was no excess tax benefit recognized.

Compensation expense related to stock option grants are recognized over the stock option's vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model. No stock options were granted during the six months ended June 30, 2017 or 2016.

During the six months ended June 30, 2017, no stock options were exercised and 14,586 stock options were forfeited by former employees. During the six months ended June 30, 2016, no stock options were exercised and stock options for 1,657 shares of common stock were forfeited.

Restricted Stock

During the six months ended June 30, 2017, the Company granted 43,000 shares of restricted common stock, which vest over three years, to newly hired employees as part of their overall compensation package. Additionally, the Company granted 338,076 shares of restricted common stock to existing employees, which vest over three years, as part of their overall compensation package, and 74,325 shares of restricted common stock, which vest over one year, to

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directors pursuant to the Company's Director Compensation Plan. The weighted average intrinsic value of the restricted shares granted during the six months ended June 30, 2017, was \$7.56 with a total fair value of approximately \$3.4 million after adjustment for an estimated weighted average forfeiture rate of 5.7%. During the six months ended June 30, 2017, 63,490 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the six months ended June 30, 2017 was approximately \$688 thousand. Approximately 1.5 million shares remained available for grant under the Amended and Restated 2009 Incentive Compensation Plan as of June 30, 2017, assuming PSUs are settled at 100% of target.

During the six months ended June 30, 2016, the Company granted 40,876 immediately vested shares of restricted common stock. Of these, 38,943 shares were granted to employees and 1,933 shares were granted to directors, all of which were issued pursuant to the Company's salary replacement program (the "Salary Replacement Program") which temporarily deferred 10% of 2015 employee salaries and director fees. Additionally, the Company granted 197,306 shares of restricted common stock to employees as part of their overall compensation package, which vest over four years, and 49,460 shares of restricted common stock to directors pursuant to the Company's Director Compensation Plan, which vest over one year. The weighted average fair value of the restricted shares granted during the six months ended June 30, 2016, was \$11.60 with a total fair value of approximately \$3.3 million after adjustment for an estimated weighted average forfeiture rate of 3.5%. During the six months ended June 30, 2016, 4,160 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the six months ended June 30, 2016 was approximately \$130 thousand.

The Company recognized approximately \$3.1 million and \$3.0 million in stock compensation expense during the six months ended June 30, 2017 and 2016, respectively, for restricted shares granted to its officers, employees and directors. As of June 30, 2017, an additional \$7.6 million of compensation expense remained to be recognized over the remaining weighted-average vesting period of 2.3 years.

Performance Stock Units

During the six months ended June 30, 2017, the Company issued 30,000 PSUs to a new employee, at a weighted average fair value of \$8.32 per unit using the Monte Carlo simulation model. An additional 160,908 PSUs were granted to executive officers, as part of their overall compensation package, at a value of \$13.91 per unit using the Monte Carlo simulation model. No PSUs were issued during the six months ended June 30, 2016. PSUs represent the opportunity to receive shares of the Company's common stock at the time of settlement. The number of shares to be awarded upon settlement of these PSUs may range from 0% to 300% of the number of PSUs awarded contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PSUs vest and settlement is determined after a three year period.

Compensation expense associated with PSUs is based on the grant date fair value of a single PSU as determined using the Monte Carlo simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As it is contemplated that the PSUs will be settled with shares of the Company's common

stock after three years, the PSU awards are accounted for as equity awards and the fair value is calculated on the grant date. The simulation model calculates the payout percentage based on the stock price performance over the performance period. The concluded fair value is based on the average achievement percentage over all the iterations. The resulting fair value expense is amortized over the life of the PSU award.

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7. Other Financial Information

The following table provides additional detail for accounts receivable, prepaid expenses and other, and accounts payable and accrued liabilities which are presented on the consolidated balance sheets (in thousands):

	June 30, 2017	December 31, 2016
Accounts receivable:		
Trade receivables	\$ 6,467	\$ 8,424
Receivable for Alta Resources Distribution	1,993	1,993
Joint interest billings	3,914	3,519
Income taxes receivable	92	91
Other receivables	(89)	3,395
Allowance for doubtful accounts	(756)	(695)
Total accounts receivable	\$ 11,621	\$ 16,727
Prepaid expenses and other:		
Prepaid insurance	\$ 1,216	\$ 1,086
Other	973	701
Total prepaid expenses and other	\$ 2,189	\$ 1,787
Accounts payable and accrued liabilities:		
Royalties and revenue payable	\$ 17,551	\$ 16,920
Advances from partners	6,480	5,792
Accrued exploration and development	9,530	11,176
Accrued leasehold costs payable	866	7,155
Trade payables	5,645	5,406
Accrued LOE & workover expense	1,180	1,867
Accrued G&A and legal expense	3,059	5,016
Other accounts payable and accrued liabilities	1,388	1,803
Total accounts payable and accrued liabilities	\$ 45,699	\$ 55,135

Included in the table below is supplemental information about certain cash and non-cash transactions during the six months ended June 30, 2017 and 2016 (in thousands):

	Six Months Ended June 30,	
	2017	2016
Cash payments:		
Interest payments	\$ 1,491	\$ 1,923
Income tax payments (refunds)	\$ 498	\$ (2,337)

Non-cash investing activities in the consolidated statements of cash flows:

Decrease in accrued capital expenditures	\$ (7,935)	\$ (2,764)
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8. Investment in Exaro Energy III LLC

The Company maintains an ownership interest in Exaro of approximately 37%.

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The following table (in thousands) presents condensed balance sheet data for Exaro as of June 30, 2017 and December 31, 2016. The balance sheet data was derived from Exaro's balance sheet as of June 30, 2017 and December 31, 2016 and was not adjusted to represent the Company's percentage of ownership interest in Exaro. The Company's share in the equity of Exaro at June 30, 2017 was approximately \$17.6 million.

	June 30, 2017	December 31, 2016
Current assets (1)	\$ 20,117	\$ 25,296
Non-current assets:		
Net property and equipment	86,561	90,621
Gas processing deposit	1,150	1,150
Other non-current assets	210	8
Total non-current assets	87,921	91,779
Total assets	\$ 108,038	\$ 117,075
Current liabilities (2)	\$ 55,796	\$ 65,694
Non-current liabilities:		
Long-term debt	—	—
Other non-current liabilities	3,418	8,106
Total non-current liabilities	3,418	8,106
Members' equity	48,824	43,275
Total liabilities & members' equity	\$ 108,038	\$ 117,075

- (1) Approximately \$16.1 million and \$19.6 million of current assets as of June 30, 2017 and December 31, 2016, respectively, is cash.
- (2) Approximately \$49.4 million and \$59.3 million of current liabilities as of June 30, 2017 and December 31, 2016, respectively, are attributable to the senior loan facility maturing September 26, 2017.

The following table (in thousands) presents the condensed results of operations for Exaro for the three and six months ended June 30, 2017 and 2016. The results of operations for the three and six months ended June 30, 2017 and 2016 were derived from Exaro's financial statements for the respective periods. The income statement data below was not adjusted to represent the Company's ownership interest but rather reflects the results of Exaro as a company. The Company's share in Exaro's results of operations recognized for the three months ended June 30, 2017 and 2016 was a gain of \$0.2 million, net of no tax expense, and a gain of \$1.3 million, net of no tax expense, respectively. The Company's share in Exaro's results of operations recognized for the six months ended June 30, 2017 and 2016 was a gain of \$2.0 million, net of no tax expense, and a gain of \$1.3 million, net of no tax expense, respectively.

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
Production:	2017	2016	2017	2016

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Oil (thousand barrels)	28	32	54	68
Gas (million cubic feet)	2,272	2,690	4,580	5,440
Total (million cubic feet equivalent)	2,442	2,882	4,902	5,848
Oil and natural gas sales	\$ 7,844	\$ 5,965	\$ 17,016	\$ 12,263
Gain (loss) on derivatives	841	(4,344)	3,402	(2,241)
Other gain	—	10,441	—	10,441
Less:				
Lease operating expenses	4,767	3,709	7,987	7,453
Depreciation, depletion, amortization & accretion	2,249	2,819	4,591	5,825
General & administrative expense	874	1,125	1,606	1,934
Income from continuing operations	795	4,409	6,234	5,251
Net interest expense	(328)	(702)	(952)	(1,396)
Net income	\$ 467	\$ 3,707	\$ 5,282	\$ 3,855

Exaro's results of operations do not include income taxes because Exaro is treated as a partnership for tax purposes.

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9. Long-Term Debt

RBC Credit Facility

In October 2013, the Company entered into a \$500 million four-year revolving credit facility with Royal Bank of Canada and other lenders (the “RBC Credit Facility”), which currently has an October 1, 2019 maturity date. The borrowing base under the facility is redetermined each November 1 and May 1. As of June 30, 2017, the borrowing base under the RBC Credit Facility was \$125 million.

As of June 30, 2017, the Company had approximately \$71.3 million outstanding under the RBC Credit Facility and \$1.9 million in outstanding letters of credit. As of December 31, 2016, the Company had approximately \$54.4 million outstanding under the RBC Credit Facility and \$1.9 million in outstanding letters of credit. As of June 30, 2017, borrowing availability under the RBC Credit Facility was \$51.8 million.

Total interest expense under the RBC Credit Facility, including commitment fees, for the three and six months ended June 30, 2017 was approximately \$0.9 million and \$1.7 million, respectively. Total interest expense under the RBC Credit Facility, including commitment fees, for the three and six months ended June 30, 2016 was approximately \$1.2 million and \$2.1 million, respectively.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the RBC Credit Facility Agreement. As of June 30, 2017, the Company was in compliance with all financial covenants under the RBC Credit Facility. The RBC Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events.

The weighted average interest rate in effect at June 30, 2017 and December 31, 2016 was 4.9% and 4.2%, respectively. The RBC Credit Facility matures on October 1, 2019, at which time any outstanding balances will be due.

10. Income Taxes

The Company's income tax provision for continuing operations consists of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Current tax provision:				
Federal	\$ —	\$ —	\$ —	\$ —
State	118	269	309	359
Total	\$ 118	\$ 269	\$ 309	\$ 359
Total tax provision:				
Federal	\$ —	\$ —	\$ —	\$ —
State	118	269	309	359
Total	\$ 118	\$ 269	\$ 309	\$ 359
Included in gain from investment in affiliates	\$ —	\$ —	\$ —	\$ —
Total income tax provision	\$ 118	\$ 269	\$ 309	\$ 359

In recording deferred income tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred income tax assets will be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, both positive and negative, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that the deferred tax assets will be realized and, therefore, established a full valuation allowance at September 30, 2015. For the six months ended June 30, 2017, the Company continues to fully value the net deferred tax asset. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

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11. Related Party Transactions

Olympic Energy Partners

Mr. Joseph J. Romano, the Chairman of the Company's board of directors, is also the President and Chief Executive Officer of Olympic Energy Partners LLC ("Olympic"). Olympic participated with the Company in the drilling of wells in March 2010, and its ownership in Company-operated wells is limited to our Dutch and Mary Rose wells.

During the three and six months ended June 30, 2017, Mr. Romano earned \$13 thousand and \$27 thousand for his service as a director of the Company, respectively. During the three and six months ended June 30, 2016, Mr. Romano earned \$12 thousand and \$26 thousand for his service as a director of the Company, respectively.

In May 2017, Mr. Romano received 14,865 shares of restricted stock, which vest in one year, as part of his board of director compensation. The Company recognized compensation expense of approximately \$33 thousand and \$62 thousand related to the shares granted to Mr. Romano for the three and six months ended June 30, 2017, respectively. In January 2016, Mr. Romano received 261 shares of restricted stock, which vested immediately, pursuant to the Salary Replacement Program and an additional 9,892 shares of restricted stock in May 2016, which vest in one year, as part of his board of director compensation. During the three and six months ended June 30, 2016, the Company recognized compensation expense of approximately \$21 thousand and \$40 thousand, respectively, related to the shares granted to Mr. Romano.

Below is a summary of payments received from (paid to) Olympic in the ordinary course of business in the Company's capacity as operator of the wells and platforms for the periods indicated. The Company made and received similar types of payments with other well owners (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Revenue payments as well owners	\$ (673)	\$ (523)	\$ (1,437)	\$ (1,171)
Joint interest billing receipts	82	60	195	122

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As of June 30, 2017 and December 31, 2016, the Company's consolidated balance sheets reflected the following balances relating to Olympic (in thousands):

	June 30, 2017	December 31, 2016
Accounts receivable:		
Joint interest billing	\$ 64	\$ 59
Accounts payable:		
Royalties and revenue payable	(476)	(557)

Oaktree Capital Management L.P.

As of June 30, 2017, Oaktree Capital Management L.P. ("Oaktree"), through various funds, owned approximately 5.1% of the Company's stock. On October 1, 2013, Mr. James Ford, then a Managing Director and Portfolio Manager within Oaktree, was elected to the Company's board of directors. Mr. Ford is currently a Senior Advisor to Oaktree.

Historically, all cash and equity awards payable to Mr. Ford were instead granted to an affiliate of Oaktree. Beginning in October 2016, all cash and equity awards payable to Mr. Ford were paid to him directly. During the three and six months ended June 30, 2017, Mr. Ford earned \$15 thousand and \$32 thousand in cash as a result of his board participation, respectively. During the three and six months ended June 30, 2016, an affiliate of Oaktree earned \$15 thousand and \$32 thousand in cash as a result of Mr. Ford's board participation, respectively.

In May 2017, Mr. Ford received 14,865 shares of restricted stock, which vest in one year, as part of his board of director compensation. The Company recognized compensation expense of approximately \$33 thousand and \$62 thousand related to the shares granted to Mr. Ford for the three and six months ended June 30, 2017, respectively. In

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January 2016, an affiliate of Oaktree received 313 shares of restricted stock, which vested immediately, pursuant to the Salary Replacement Program and an additional 9,892 shares of restricted stock in May 2016, which vest in one year, as part of Mr. Ford's board of director compensation. During the three and six months ended June 30, 2016, the Company recognized compensation expense of approximately \$21 thousand and \$40 thousand, respectively, related to the shares granted to an affiliate of Oaktree.

12. Commitments and Contingencies

Legal Proceedings

From time to time, the Company is involved in legal proceedings relating to claims associated with its properties, operations or business or arising from disputes with vendors in the normal course of business, including the material matters discussed below.

In July 2010, several parties associated with a limited partnership, formed to invest in oil and gas properties, that was dissolved in 1995 filed suit against a subsidiary of the Company and several co-defendants in district court for Madison County in Texas. The plaintiffs claim to own or have rights in certain oil and gas properties situated in Madison County, Texas by virtue of the partnership having interests in addition to those it held of record at the time of its dissolution, which were distributed to the partners in connection with such dissolution. A predecessor of the subsidiary of the Company involved in this case acquired a portion of the interests now claimed by the plaintiffs from a successor to the general partner of the aforementioned partnership in 2000. The plaintiffs' expert has provided a range of estimated monetary damages of up to approximately \$9.4 million as to the Company's subsidiary. The Company is vigorously defending this lawsuit and believes that it has meritorious defenses.

In November 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decade-old poorly documented transactions. Based on prior summary judgments, the trial court has entered a final judgment in the case in favor of the plaintiffs for approximately \$5.3 million, plus post-judgment interest. The Company is vigorously defending this lawsuit, believes that it has meritorious defenses and is appealing the trial court's decision to the applicable state Court of Appeals.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by the Company in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the district court for Liberty County, Texas and combined with a suit filed by other parties against the

plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). The Company has made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately \$10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. The trial court has entered judgment in favor of the Company's subsidiary and the successors to the grantors under the aforementioned deeds. The plaintiff is appealing the trial court's decision to the applicable state Court of Appeals. The Company is vigorously defending this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

While many of these matters involve inherent uncertainty and the Company is unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company maintains various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

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Throughput Contract Commitment

The Company signed a throughput agreement with a third party pipeline owner/operator that constructed a natural gas gathering pipeline in the Company's Southeast Texas area that allows the Company to defray the cost of building the pipeline itself. The Company currently forecasts that monthly gas volume deliveries through this line in its Southeast Texas area will not meet minimum throughput requirements under the agreement. Without further development in that area, the volume deficiency will continue through the expiration of the throughput commitment in March 2020. The throughput deficiency fee is paid in April of each calendar year. The Company estimates that the net deficiency fee will be in the range of \$1.5 to \$1.6 million annually for the remaining contract period, based upon forecasted production volumes from existing proved producing reserves only, assuming no future development during this commitment period. As of June 30, 2017, based upon the current commodity price market and our short term strategic drilling plans, the Company has recorded a \$0.8 million loss contingency through December 31, 2017. The Company will continue to assess this commitment in light of its development plans for this area.

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Available Information

General information about us can be found on our website at www.contango.com. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission ("SEC"). We are not including the information on our website as a part of, or incorporating it by reference into, this Report.

Cautionary Statement about Forward-Looking Statements

Certain statements contained in this report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases "should be", "will be", "believe", "expect", "anticipate", "estimate", "forecast", "goal" and similar expressions identify forward-looking statements and express our expectations about future events. Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements are made subject to certain risks and uncertainties that could cause actual results to differ materially from those stated. Risks and uncertainties that could cause or contribute to such differences include, without limitation, those discussed in the section entitled "Risk Factors" included in our Annual Report on Form 10-K and those factors summarized below:

- our ability to successfully develop our recent acquisition of undeveloped acreage in the Southern Delaware Basin, integrate the operations relating thereto with our existing operations and realize the benefits of such acquisition;
- our financial position;
- our business strategy, including outsourcing;
- meeting our forecasts and budgets;
- expectations regarding natural gas and oil markets in the United States;
- natural gas and oil price volatility;
- operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and natural gas processing facilities;
- the risks associated with operating deep high pressure and temperature wells, including well blowouts and explosions;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which we have made a large capital commitment relative to the size of our capitalization structure;
- the timing and successful drilling and completion of natural gas and oil wells;
- availability of capital and the ability to repay indebtedness when due;
- availability and cost of rigs and other materials and operating equipment;
- timely and full receipt of sale proceeds from the sale of our production;
- the ability to find, acquire, market, develop and produce new natural gas and oil properties;

- interest rate volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- operating hazards attendant to the natural gas and oil business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures, and other risks;
 - downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps;
- actions or inactions of third-party operators of our properties;
- actions or inactions of third-party operators of pipelines or processing facilities;
- the ability to find and retain skilled personnel;
- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals;
- worldwide economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;

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- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our natural gas and oil discoveries;
- expanded rigorous monitoring and testing requirements; and
- our ability to obtain insurance coverage on commercially reasonable terms.

Any of these factors and other factors described in this report could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. Although we believe our estimates and assumptions to be reasonable when made, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. We caution you that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. All forward-looking statements speak only as of the date of this report.

We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

You should not unduly rely on these forward-looking statements in this report, as they speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and the accompanying notes and other information included elsewhere in this Quarterly Report on Form 10-Q and in our 2016 Form 10-K, previously filed with the Securities and Exchange Commission ("SEC").

Overview

We are a Houston, Texas based, independent oil and natural gas company. Our business is to maximize production and cash flow from our offshore properties in the shallow waters of the Gulf of Mexico ("GOM") and onshore Texas and Wyoming properties and to use that cash flow to explore, develop, exploit and acquire crude oil and natural gas properties in the Texas and Rocky Mountain regions of the United States.

The following table lists our primary producing areas as of June 30, 2017:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Zavala and Dimmit counties, Texas	Buda / Austin Chalk
Weston County, Wyoming	Muddy Sandstone
Pecos County, Texas	Southern Delaware Basin (Wolfcamp)
Texas Gulf Coast	Conventional and unconventional formations
Sublette County, Wyoming	Jonah Field (1)

(1) Through a 37% equity investment in Exaro Energy III LLC ("Exaro"). Production associated with this investment is not included in our reported production results for the three months ended June 30, 2017.

In July 2016, we purchased approximately 12,100 gross operated undeveloped acres (5,000 net acres) in the Southern Delaware Basin in Pecos County, Texas (the "Acquisition"), which we began drilling during the fourth quarter of 2016, and increased our acreage to approximately 13,500 gross operated acres (6,700 net) as of June 30, 2017.

Our remaining 2017 capital program will focus on the development of our Southern Delaware Basin acreage, while preserving our healthy financial position. Additionally, we will continue to identify opportunities for cost efficiencies

in all areas of our operations, maintain core leases and continue to identify new resource potential opportunities internally and, where appropriate, through acquisition. We will continuously monitor the commodity price environment, including its stability and forecast, and, if warranted, make adjustments to our strategy as the year progresses.

Capital Expenditures

Our newly acquired Southern Delaware Basin acreage is expected to generate positive returns on drilling investment, even in the current commodity price environment. Assuming we achieve our expected results and market conditions do not deteriorate, we will continue to drill throughout the year. Until a sustained improvement in commodity prices occurs, however, we do not currently expect to devote meaningful capital to the development of our other areas, and will devote capital in those areas only to fulfill commitments, preserve core acreage and, where determined appropriate to do so, expand our presence in existing areas. We will continue to make balance sheet strength a priority in 2017, will continue to evaluate new organic opportunities for growth and will continue to evaluate pursuing stressed or distressed acquisition opportunities that may arise in this low commodity price environment. We retain the flexibility to be more aggressive in our drilling plans should actual results exceed expectations and/or commodity prices improve, thereby making increased drilling an appropriate business decision.

Southern Delaware Basin

Since the closing of the Acquisition in late July 2016, we and our partner have increased our leasehold footprint to approximately 6,700 operated acres, net to Contango. As of June 30, 2017, we currently estimate that we have close to 200 gross drilling locations in the Southern Delaware Basin, initially targeting the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. Substantially all of these locations can accommodate 10,000 foot laterals. In January

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2017, we initiated flowback on our first well in the Southern Delaware Basin, the Lonestar-Gunfighter #1H, an Upper Wolfcamp test well in the northwest portion of our acreage position, on a controlled flow basis, reaching a maximum 24-hour initial production (“IP”) rate of 966 Boed (72% oil).

Our next two wells, the Rude Ram #1H and the Ripper State #1H, were drilled from a common surface location one mile south of the Lonestar-Gunfighter #1H, each well also targeting the Upper Wolfcamp. Both wells initiated flow back in May 2017. The Rude Ram #1H reached a maximum 24-hour IP rate of 1,304 Boed (69% oil), while the Ripper State #1H reached a maximum 24-hour IP rate of 1,131 Boed (73% oil). In February 2017, we spud a pilot test well, the Grim Reaper #1H, approximately 1.5 miles to the southeast of the Rude Ram and Ripper State. The Grim Reaper was initially drilled as a vertical pilot well through the Lower Wolfcamp, and after experiencing casing problems in the intermediate hole section, logs were run, and the well was completed vertically with multistage fracs in the Lower Wolfcamp to evaluate future potential.

Our fourth well in the area, the Gunner #2H, was spud in April 2017, approximately two miles to the northeast of the Grim Reaper #1H. The Gunner #2H is currently being completed, with flow back expected to begin in early August. Our fifth and sixth wells in this area, the Fighting Ace #1H and Crusader #1H are currently being drilled. Completion operations on both wells are expected to commence later in the third quarter, with initial production expected in the fourth quarter.

Impairment of Long-Lived Assets

We recognized no impairment of proved properties during the three and six months ended June 30, 2017. Under GAAP, an impairment charge is required when the unamortized capital cost of any individual property within the Company’s producing property base exceeds the risked estimated future net cash flows from the proved, probable and possible reserves for that property. We recognized \$1.4 million in impairment expense related to the partial impairment of two unused offshore platforms for the three and six months ended June 30, 2017.

Summary Production Information

Our production for the three months ended June 30, 2017 was approximately 68% offshore and 32% onshore and was comprised of 68% natural gas, 16% oil and 16% natural gas liquids. Our production for the three months ended June 30, 2016 was 67% offshore and 33% onshore and was comprised of approximately 69% natural gas, 15% oil and 16% natural gas liquids.

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The table below sets forth our average net daily production data in Mmcfe/d for each of our fields for each of the periods indicated:

	Three Months Ended				
	June 30, 2016	September 30, 2016	December 31, 2016	March 31, 2017	June 30, 2017
Offshore GOM					
Dutch and Mary					
Rose (1)	43.3	39.3	39.5	35.4	36.3
Vermilion 170 (2)	6.2	4.0	4.9	4.6	3.1
Other offshore (3)	0.6	0.6	0.6	0.5	0.2
Southeast Texas (4)	13.9	12.1	10.1	8.6	8.2
South Texas (5)	7.4	7.5	7.5	6.4	5.6
Other (6)	3.2	2.2	1.7	2.1	4.6
	74.6	65.7	64.3	57.6	58.0

-
- (1) Includes 26 day shut in for compressor repair during the three months ended March 31, 2017.
- (2) Includes a decreased production rate of 0.8 Mmcfe/d due to temporary pipeline limitations during the three months ended June 30, 2017.
- (3) Includes Ship Shoal 263 and South Timbalier 17.
- (4) Includes Madison and Grimes counties, among others.
- (5) Includes Zavala and Dimmit counties, among others.
- (6) Includes onshore wells primarily in Colorado, East Texas, and Wyoming during 2016 and onshore wells primarily in East Texas, Wyoming and West Texas during 2017.

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Other Investments

Jonah Field - Sublette County, Wyoming

Our wholly owned subsidiary, Contaro Company (“Contaro”) currently has a 37% ownership interest in Exaro. As of June 30, 2017, Exaro had 646 wells on production over its 5,760 gross acres (1,040 net), with a working interest between 2.4% and 32.5%. These wells were producing at a rate of approximately 27 Mmcfd, net to Exaro. The operator of these interests has applied for multiple drilling permits for horizontal wells that will be located on parts of our acreage. Exaro believes that one of these wells could be permitted by as early as year-end 2017. Exaro’s working interest in the drilling spacing units for these horizontal wells ranges from 1% to 6%. For the three months ended June 30, 2017 and 2016, we recognized a net investment gain of approximately \$0.2 million, net of no tax expense, and a gain of approximately \$1.3 million, net of no tax expense, respectively, as a result of our investment in Exaro. For the six months ended June 30, 2017 and 2016, we recognized a net investment gain of approximately \$2.0 million, net of no tax expense, and a gain of approximately \$1.3 million, net of no tax expense, respectively. See Note 8 to our Financial Statements - “Investment in Exaro Energy III LLC” for additional details related to this investment.

Other

We intend to continue to evaluate potential acquisition opportunities to expand our presence in resource plays, to exploit our oil and liquids-rich positions and to continue to develop exploration and exploitation opportunities where commodity price-justified. Acquisition efforts will typically be focused on areas in which we can leverage our geographic and geological expertise to exploit identified drilling opportunities and where we can develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves.

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Results of Operations for the Three and Six Months Ended June 30, 2017 and 2016

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from operations for the three and six months ended June 30, 2017 and 2016. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six thousand cubic feet ("Mcf") of natural gas. Reported lease operating expenses include production taxes, such as ad valorem and severance taxes.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2017	2016	%		2017	2016	%	
Revenues (thousands):								
Oil and condensate sales	\$ 6,483	\$ 6,971	(7) %		\$ 12,025	\$ 12,218	(2) %	
Natural gas sales	11,135	9,337	19 %		22,275	19,272	16 %	
NGL sales	2,658	3,054	(13) %		5,400	5,454	(1) %	
Total revenues	\$ 20,276	\$ 19,362	5 %		\$ 39,700	\$ 36,944	7 %	
Production:								
Oil and condensate (thousand barrels)								
Offshore GOM	33	36	(8) %		55	87	(37) %	
Southeast Texas	38	63	(40) %		82	136	(40) %	
South Texas	23	33	(30) %		49	67	(27) %	
Other	48	35	37 %		70	62	13 %	
Total oil and condensate	142	167	(15) %		256	352	(27) %	
Natural gas (million cubic feet)								
Offshore GOM	2,908	3,676	(21) %		5,916	7,515	(21) %	
Southeast Texas	340	554	(39) %		675	1,197	(44) %	
South Texas	276	366	(25) %		605	730	(17) %	
Other	83	77	8 %		139	152	(9) %	
Total natural gas	3,607	4,673	(23) %		7,335	9,594	(24) %	
Natural gas liquids (thousand barrels)								
Offshore GOM	83	111	(25) %		167	223	(25) %	
Southeast Texas	29	56	(48) %		58	123	(53) %	
South Texas	16	18	(11) %		30	36	(17) %	
Other	8	1	700 %		9	4	125 %	
Total natural gas liquids	136	186	(27) %		264	386	(32) %	
Total (million cubic feet equivalent)								
Offshore GOM	3,602	4,559	(21) %		7,248	9,379	(23) %	
Southeast Texas	747	1,263	(41) %		1,517	2,753	(45) %	
South Texas	509	676	(25) %		1,083	1,346	(20) %	
Other	419	295	42 %		609	541	13 %	
Total production	5,277	6,793	(22) %		10,457	14,019	(25) %	

Daily Production:

Oil and condensate (thousand barrels per day)

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Offshore GOM	0.4	0.4	(8) %	0.3	0.5	(37) %
Southeast Texas	0.4	0.7	(40) %	0.5	0.7	(40) %
South Texas	0.3	0.4	(30) %	0.3	0.4	(27) %
Other	0.5	0.3	37 %	0.3	0.3	13 %
Total oil and condensate	1.6	1.8	(15) %	1.4	1.9	(27) %
Natural gas (million cubic feet per day)						
Offshore GOM	32.0	40.4	(21) %	32.7	41.2	(21) %
Southeast Texas	3.7	6.1	(39) %	3.7	6.6	(44) %
South Texas	3.0	4.0	(25) %	3.3	4.0	(17) %
Other	0.9	0.9	8 %	0.8	0.9	(9) %
Total natural gas	39.6	51.4	(23) %	40.5	52.7	(24) %

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	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	%	2017	2016	%
Natural gas liquids (thousand barrels per day)						
Offshore GOM	0.9	1.2	(25) %	0.9	1.2	(25) %
Southeast Texas	0.3	0.6	(48) %	0.3	0.7	(53) %
South Texas	0.2	0.2	(11) %	0.2	0.2	(17) %
Other	0.1	—	700 %	0.1	—	125 %
Total natural gas liquids	1.5	2.0	(27) %	1.5	2.1	(32) %
Total (million cubic feet equivalent per day)						
Offshore GOM	39.6	50.1	(21) %	40.0	51.5	(23) %
Southeast Texas	8.2	13.9	(41) %	8.4	15.1	(45) %
South Texas	5.6	7.4	(25) %	6.0	7.4	(20) %
Other	4.6	3.2	42 %	3.4	3.0	13 %
Total production	58.0	74.6	(22) %	57.8	77.0	(25) %
Average Sales Price:						
Oil and condensate (per barrel)	\$ 45.61	\$ 41.80	9 %	\$ 46.99	\$ 34.75	35 %
Natural gas (per thousand cubic feet)	\$ 3.09	\$ 2.00	55 %	\$ 3.04	\$ 2.01	51 %
Natural gas liquids (per barrel)	\$ 19.50	\$ 16.33	19 %	\$ 20.40	\$ 14.09	45 %
Total (per thousand cubic feet equivalent)	\$ 3.84	\$ 2.85	35 %	\$ 3.80	\$ 2.63	44 %
Expenses (thousands):						
Operating expenses	\$ 6,329	\$ 7,020	(10) %	\$ 13,162	\$ 14,624	(10) %
Exploration expenses	\$ 284	\$ 324	(12) %	\$ 375	\$ 644	(42) %
Depreciation, depletion and amortization	\$ 12,714	\$ 17,875	(29) %	\$ 24,485	\$ 34,420	(29) %
Impairment and abandonment of oil and gas properties	\$ 1,401	\$ 1,252	12 %	\$ 1,431	\$ 3,103	(54) %
General and administrative expenses	\$ 5,833	\$ 5,384	8 %	\$ 12,429	\$ 11,286	10 %
Gain from investment in affiliates (net of taxes)	\$ 166	\$ 1,295	(87) %	\$ 1,950	\$ 1,335	46 %
Selected data per Mcfe:						
Operating expenses	\$ 1.20	\$ 1.03	17 %	\$ 1.26	\$ 1.04	21 %
General and administrative expenses	\$ 1.11	\$ 0.79	41 %	\$ 1.19	\$ 0.81	47 %
Depreciation, depletion and amortization	\$ 2.41	\$ 2.63	(8) %	\$ 2.34	\$ 2.46	(5) %

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

Natural Gas, Oil and NGL Sales and Production

All of our revenues are from the sale of our natural gas, oil and NGL production. Our revenues may vary significantly from year to year depending on production volumes and changes in commodity prices, each of which may fluctuate widely. Our production volumes are subject to significant variation as a result of new operations, weather events, transportation and processing constraints and mechanical issues. In addition, our production naturally declines over time as we produce our reserves.

We reported revenues of \$20.3 million for the three months ended June 30, 2017, compared to revenues of \$19.4 million for the three months ended June 30, 2016. The increase in revenues was attributable to higher commodity prices, which offset the decline in production caused by limited drilling in 2016 due to the low and uncertain commodity price environment.

Total equivalent production was 58.0 Mmcfd for the three months ended June 30, 2017, compared to 74.6 Mmcfd in the prior year quarter. The decrease was attributable to a 10.5 Mmcfd decline in production from our offshore properties as a result of normal field decline and 61 days of decreased production rates at the Vermillion 170 field due to temporary pipeline limitations, as well as a 9.4 Mmcfd decline in our onshore properties due to non-core property sales and normal field decline. The decrease in production was partially offset by 3.3 Mmcfd of new production from drilling on our Southern Delaware Basin acreage.

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Average Sales Prices

The average equivalent sales price realized for the three months ended June 30, 2017 was \$3.84 per Mcfe compared to \$2.85 per Mcfe for the three months ended June 30, 2016. This increase was attributable primarily to the increase in the realized price of oil to \$45.61 per barrel, compared to \$41.80 per barrel for the three months ended June 30, 2016, and to the increase in the realized price of natural gas to \$3.09 per Mcf, compared to \$2.00 per Mcf for the three months ended June 30, 2016.

Operating Expenses

Operating expenses for the three months ended June 30, 2017 were approximately \$6.3 million, or \$1.20 per Mcfe, compared to \$7.0 million, or \$1.03 per Mcfe, for the three months ended June 30, 2016. The table below provides additional detail of operating expenses for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,			
	2017		2016	
	(in thousands)(per Mcfe)		(in thousands)(per Mcfe)	
Lease operating expenses	\$ 4,195	0.79	\$ 4,756	\$ 0.70
Production & ad valorem taxes	709	0.13	1,160	0.17
Transportation & processing costs	1,073	0.20	790	0.11
Workover costs	352	0.08	314	0.05
Total operating expenses	\$ 6,329	1.20	\$ 7,020	\$ 1.03

Lease operating expenses decreased by 12% for the three months ended June 30, 2017, compared to the three months ended June 30, 2016, as a result of our efforts to reduce costs during this challenging commodity price environment and non-core property sales.

Production and ad valorem taxes decreased by 39% for the three months ended June 30, 2017, compared to the three months ended June 30, 2016, primarily as a result of property sales, declining property valuations and production volumes and prior period adjustments.

Transportation & processing costs increased by 36% for the three months ended June 30, 2017, compared to the three months ended June 30, 2016, due to a final minimum volume charge on two wells in our South Texas region and

additional transportation costs from additional allocated volumes that were sold in our Dutch and Mary Rose Field.

Impairment Expenses

Impairment expense for the three months ended June 30, 2017 was \$1.4 million related to the partial impairment of two unused offshore platforms. Impairment expense for the three months ended June 30, 2016 included a \$1.1 million impairment and partial impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases, substantially all of which was related to unproved lease cost amortization of properties in Fayette and Gonzales counties Texas.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the three months ended June 30, 2017 was approximately \$12.7 million, or \$2.41 per Mcfe. This compares to approximately \$17.9 million, or \$2.63 per Mcfe, for the three months ended June 30, 2016. The lower depletion for the three months ended June 30, 2017 was primarily attributable to lower production.

General and Administrative Expenses

General and administrative expenses for the three months ended June 30, 2017 were approximately \$5.8 million, compared to \$5.4 million for the three months ended June 30, 2016. General and administrative expenses are primarily related to cash compensation and benefits, stock based compensation, professional fees and office costs.

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General and administrative expenses included approximately \$1.6 million and \$1.3 million in non-cash stock based compensation, for the current and prior year quarters, respectively.

Gain from Affiliates

For the three months ended June 30, 2017, the Company recorded a gain from affiliates of approximately \$0.2 million, net of no tax expense, related to our investment in Exaro, compared to a gain of \$1.3 million, net of no tax expense, for three months ended June 30, 2016.

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

Natural Gas, Oil and NGL Sales and Production

All of our revenues are from the sale of our natural gas, oil and NGL production. Our revenues may vary significantly from year to year depending on production volumes and changes in commodity prices, each of which may fluctuate widely. Our production volumes are subject to significant variation as a result of new operations, weather events, transportation and processing constraints and mechanical issues. In addition, our production naturally declines over time as we produce our reserves.

We reported revenues of \$39.7 million for the six months ended June 30, 2017, compared to revenues of \$36.9 million for the six months ended June 30, 2016. The increase in revenues was attributable to higher commodity prices, which offset the decline in production caused by limited drilling in 2016 due to the low and uncertain commodity price environment.

Total equivalent production was 57.8 Mmcfd for the six months ended June 30, 2017, compared to 77.0 Mmcfd for the six months ended June 30, 2016. The decrease was attributable to a 11.5 Mmcfd decline in production from our offshore properties as a result of normal field decline, 61 days of decreased production rates at the Vermillion 170 field due to temporary pipeline limitations, and a 26 day shut in for compressor repair at the Dutch Mary Rose field, as well as a 9.7 Mmcfd decline in our onshore properties due to non-core property sales and normal field decline. The decrease in production was partially offset by 2.0 Mmcfd of new production from drilling on our Southern Delaware Basin acreage.

Average Sales Prices

The average equivalent sales price realized for the six months ended June 30, 2017 was \$3.80 per Mcfe compared to \$2.63 per Mcfe for the six months ended June 30, 2016. This increase was attributable primarily to the increase in the realized price of oil to \$46.99 per barrel, compared to \$34.75 per barrel for the six months ended June 30, 2016, and to the increase in the realized price of natural gas to \$3.04 per Mcf, compared to \$2.01 per Mcf for the six months ended June 30, 2016.

Operating Expenses

Operating expenses for the six months ended June 30, 2017 were approximately \$13.2 million, or \$1.26 per Mcfe, compared to \$14.6 million, or \$1.04 per Mcfe, for the six months ended June 30, 2016. The table below provides additional detail of operating expenses for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30, 2017		2016	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	\$ 8,843	\$ 0.85	\$ 9,907	\$ 0.70
Production & ad valorem taxes	1,368	0.13	2,054	0.15
Transportation & processing costs	2,114	0.20	2,209	0.16
Workover costs	837	0.08	454	0.03
Total operating expenses	\$ 13,162	1.26	\$ 14,624	\$ 1.04

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Lease operating expenses decreased by 11% for the six months ended June 30, 2017, compared to the six months ended June 30, 2016, as a result of our efforts to reduce costs during this challenging commodity price environment and non-core property sales.

Production and ad valorem taxes decreased by 33% for the three months ended June 30, 2017, compared to the three months ended June 30, 2016, primarily as a result of property sales, declining property valuations and production volumes and prior period adjustments

Impairment Expenses

Impairment expense for the six months ended June 30, 2017 was \$1.4 million related to the partial impairment of two unused offshore platforms. Impairment expense for the six months ended June 30, 2016 included a \$0.7 million impairment of proved properties. Substantially all of the non-cash impairment charge in the prior year period was related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Impairment expense for the six months ended June 30, 2016 also included a \$2.3 million impairment and partial impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases, substantially all of which was related to unproved lease cost amortization of properties in Fayette and Gonzales counties Texas.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the six months ended June 30, 2017 was approximately \$24.5 million, or \$2.34 per Mcfe. This compares to approximately \$34.4 million, or \$2.46 per Mcfe, for the six months ended June 30, 2016. The lower depletion for the six months ended June 30, 2017 was primarily attributable to lower production.

General and Administrative Expenses

General and administrative expenses for the six months ended June 30, 2017 were approximately \$12.4 million, compared to \$11.3 million for the six months ended June 30, 2016. General and administrative expenses are primarily related to cash compensation and benefits, stock based compensation, professional fees and office costs. General and administrative expenses for the current year included approximately \$3.1 million in non-cash stock based compensation, while the prior year included approximately \$3.0 million in non-cash stock based compensation.

Gain from Affiliates

For the six months ended June 30, 2017, the Company recorded a gain from affiliates of approximately \$2.0 million, net of no tax expense, related to our investment in Exaro, compared to a gain of \$1.3 million, net of no tax expense, for six months ended June 30, 2016.

Capital Resources and Liquidity

During the six months ended June 30, 2017, we incurred expenditures of \$33.1 million on capital projects, including \$3.6 million in paid and accrued leasehold acquisition costs and \$29.2 million for the drilling and completion of wells in the Southern Delaware Basin.

Our capital expenditure budget for 2017 was originally forecast to be \$46.3 million, including \$36.6 million to drill and/or complete nine gross wells (4.0 net) on our Southern Delaware Basin acreage. As a result of the success of our first well in the Southern Delaware Basin acreage, and other factors, we revised our 2017 budget to include an additional \$9.0 million in drilling and completion costs for one additional gross well (0.5 net) and a saltwater disposal well, which increases our current forecast for the year to \$55.3 million.

Additionally, the Company often reviews acquisitions and prospects presented to us by third parties, and we may decide to invest in one or more of these opportunities. There can be no assurance that we will invest or that any investment we enter into will be successful. These potential investments are not part of our current capital budget and could require us to invest additional capital. Natural gas and oil prices continue to be volatile and our resources may not be sufficient to fund these opportunities.

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Cash From Operating Activities

Cash flows from operating activities provided approximately \$18.1 million in cash for the six months ended June 30, 2017 compared to \$13.1 million provided by operating activities for the same period in 2016. The table below provides additional detail of cash flows from operating activities for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
	2017	2016
	(in thousands)	
Cash flows from operating activities, exclusive of changes in working capital accounts	\$ 14,785	\$ 14,249
Changes in operating assets and liabilities	3,324	(1,172)
Net cash provided by operating activities	\$ 18,109	\$ 13,077

Cash From Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2017 were approximately \$34.9 million, substantially all of which was used for capital expenditures related to drilling and/or completing wells in the Southern Delaware Basin and acquiring or extending unproved leases in our core areas. Cash flows used in investing activities for the six months ended June 30, 2016 were approximately \$7.4 million all of which was used for capital expenditures related to completing a well in our Wyoming area and acquiring or extending unproved leases in our core areas. Amounts presented include cash payments for accrued amounts at the beginning of each period.

Cash From Financing Activities

Cash flows provided by financing activities for the six months ended June 30, 2017 were approximately \$16.8 million, primarily related to net borrowings under our credit facility with the Royal Bank of Canada and other lenders (the "RBC Credit Facility"). Cash flows used in financing activities for the six months ended June 30, 2016 were approximately \$5.7 million, primarily related to the repayment of net borrowings under our RBC Credit Facility.

RBC Credit Facility

In October 2013, the Company entered into a \$500 million four-year revolving credit facility with Royal Bank of Canada and other lenders, which currently has an October 1, 2019 maturity date. The borrowing base is redetermined each November and May. Effective May 4, 2017, as part of the regular redetermination schedule, the borrowing base under the RBC Credit Facility was redetermined at \$125 million.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the RBC Credit Facility Agreement. As of June 30, 2017, we were in compliance with all covenants under the RBC Credit Facility. The RBC Credit Facility also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events.

Application of Critical Accounting Policies and Management's Estimates

Significant accounting policies that we employ and information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate are presented in Note 2 to our Financial Statements – “Summary of Significant Accounting Policies” of this report and in Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – “Application of Critical Accounting Policies and Management’s Estimates” in our 2016 Form 10-K.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements, see Note 2 to our Financial Statements – “Summary of Significant Accounting Policies.”

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Off Balance Sheet Arrangements

We may enter into off-balance sheet arrangements that can give rise to off-balance sheet obligations. As of June 30, 2017, the primary off-balance sheet arrangements that we have entered into are operating lease agreements, which are customary in the oil and gas industry. Other than the off-balance sheet arrangements shown under operating leases in the commitments and contingencies table included in our 2016 Form 10-K, we have no other off-balance sheet arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

We are exposed to various risks including energy commodity price risk for our natural gas and oil production. When oil, natural gas and natural gas liquids prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. Our major commodity price risk exposure is to the prices received for our oil, natural gas and natural gas liquids production. Realized commodity prices received for our production are tied to the spot prices applicable to natural gas and crude oil at the applicable delivery points. Prices received for oil, natural gas and natural gas liquids are volatile and unpredictable. For the six months ended June 30, 2017, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate \$2.0 million impact on our revenues.

Derivative Instruments and Hedging Activity

We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management strategy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our cash flows. The types of derivative instruments that we typically utilize include swaps and costless collars. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 50% of forecasted production from proved developed producing reserves (excluding forecasted offshore production during hurricane season), at the time of hedging, for the following twelve to eighteen months. Our hedge strategy and objectives may change significantly as our operational profile changes and/or commodity prices change.

We are exposed to market risk on our open derivative contracts related to potential nonperformance by our counterparties. It is our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The counterparties to the Company's current derivative contracts are large financial institutions and also lenders or affiliates of lenders in its RBC Credit Facility. We are not required to post collateral, or pay margin calls, under any of these contracts as they are secured under our RBC Credit Facility.

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Currently, we do not have any derivative contracts to reduce the exposure to market rate fluctuations. At June 30, 2017, we did not have any open positions that converted our variable interest rate debt to fixed interest rates. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

We account for our derivative activities under the provisions of ASC 815, Derivatives and Hedging, ("ASC 815"). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. The estimated fair values for financial instruments under ASC 825, Financial Instruments ("ASC 825") are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Note 5 to our Financial Statements - "Derivative Instruments" for more details.

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Interest Rate Sensitivity

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and US Prime based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

As of June 30, 2017, our total long-term debt was \$71.3 million, which bears interest at a floating or market interest rate that is tied to the prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During the six months ended June 30, 2017, our effective rates fluctuated between 4.2% and 7.3%, depending on the term of the specific debt drawdowns. At June 30, 2017, we did not have any outstanding interest rate swap agreements. As of June 30, 2017, the weighted average interest rate on our variable rate debt was 4.91% per year. Assuming our current level of borrowings, a 100 basis point increase in the interest rates we pay under our RBC Credit Facility would result in an increase of our interest expense by \$0.4 million for the six month period.

Other Financial Instruments

As of June 30, 2017, we had no cash or cash equivalents based on our cash management policy. Investments in fixed-rate, interest-earning instruments carry a degree of interest rate and credit rating risk. Fixed-rate securities may have their fair market value adversely impacted because of changes in interest rates and credit ratings. Additionally, the value of our investments may be impaired temporarily or permanently. Due in part to these factors, our investment income may decline and we may suffer losses in principal. Currently, we do not use any derivative or other financial instruments or derivative commodity instruments to hedge any market risks, including changes in interest rates or credit ratings, and we do not plan to employ these instruments in the future. Because of the nature of the issuers of the securities that we invest in, we do not believe that we have any cash flow exposure arising from changes in credit ratings. Based on a sensitivity analysis performed on the financial instruments held as of June 30, 2017, an immediate 10% change in interest rates would result in a \$0.3 million change on our near-term financial condition or results of operations.

Item 4. Controls and Procedures

Our President and Chief Executive Officer, together with our Chief Financial Officer and Chief Accounting Officer, carried out an evaluation of the effectiveness of the Company's "disclosure controls and procedures" as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as of June 30, 2017. Based upon that evaluation, the Company's management concluded that, as of June 30, 2017, the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to ensure 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 our management, including our President and Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosure.

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

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of legal proceedings, see Note 12 to our Financial Statements – “Commitments and Contingencies.”

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A of Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2016.

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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.

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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, thereto duly authorized.

CONTANGO OIL & GAS COMPANY

Date: August 3, 2017 By: /S/ ALLAN D. KEEL
Allan D. Keel
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 3, 2017 By: /S/ E. JOSEPH GRADY
E. Joseph Grady
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 3, 2017 By: /S/ DENISE DUBARD
Denise DuBard
Chief Accounting Officer and Controller
(Principal Accounting Officer)

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Exhibit Number	Description
3.1	<u>Certificate of Incorporation of Contango Oil & Gas Company.</u> (1)
3.2	<u>Amendment to the Certificate of Incorporation of Contango Oil & Gas Company.</u> (2)
3.3	<u>Third Amended and Restated Bylaws of Contango Oil & Gas Company.</u> (3)
10.1	* <u>Form of Contango Oil and Gas Company Stock Award Agreement (employees).</u> (4)
10.2	* <u>Form of Contango Oil and Gas Company Stock Award Agreement (executives).</u> (4)
10.3	* <u>Contango Oil and Gas Director Compensation Plan.</u> (4)
31.1	<u>Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.</u> †
31.2	<u>Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.</u> †
32.1	<u>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.</u> †
32.2	<u>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.</u> †
101	Interactive Data Files †

† Filed herewith.

* Indicates a management contract or compensatory plan or arrangement.

1. Filed as an exhibit to the Company's Current Report on Form 8-K dated December 1, 2000, as filed with the Securities and Exchange Commission on December 15, 2000.
2. Filed as an exhibit to the Company's Quarterly Report on Form 10-QSB for the quarter ended September 30, 2002, as filed with the Securities and Exchange Commission on November 14, 2002.
3. Filed as an exhibit to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, as filed with the Securities and Exchange Commission on March 3, 2015.
4. Filed as an exhibit to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, as filed with the Securities and Exchange Commission on May 10, 2017.

