CONTANGO OIL & GAS CO
Form 10-Q
November 07, 2018
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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 September 30, 2018

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	77002

HOUSTON, TEXAS
(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 every Interactive Data File required to be submitted 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 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 November 5, 2018 was 25,583,398.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

QUARTERLY REPORT ON FORM 10-Q

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2018

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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)

	September 30, 2018	December 31, 2017
	(unaudited)	
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net	10,957	13,059
Prepaid expenses	1,191	1,892
Current derivative asset	43	822
Held for sale (see Note 3)	1,748	—
Total current assets	13,939	15,773
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,156,557	1,239,662
Unproved properties	34,295	35,243
Held for sale (see Note 3)	8,248	—
Other property and equipment	1,272	1,272
Accumulated depreciation, depletion and amortization	(929,416)	(930,220)
Total property, plant and equipment, net	270,956	345,957
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	18,426	18,464
Long-term derivative asset	39	—
Deferred tax asset	424	424
Other	477	835
Total other non-current assets	19,366	19,723
TOTAL ASSETS	$ 304,261	$ 381,453
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 52,899	$ 46,755
Current derivative liability	3,118	1,765
Current asset retirement obligations	747	2,017
Held for sale (see Note 3)	1,440	—
Total current liabilities	58,204	50,537
NON-CURRENT LIABILITIES:		
Long-term debt	81,771	85,380
Long-term derivative liability	759	300
Asset retirement obligations	17,837	20,388
Other long term liabilities	3,298	248

Held for sale (see Note 3)	2,155	—
Total non-current liabilities	105,820	106,316
Total liabilities	164,024	156,853
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 31,029,458 shares issued and 25,584,108 shares outstanding at September 30, 2018, 30,873,470 shares issued and 25,505,715 shares outstanding at December 31, 2017	1,229	1,223
Additional paid-in capital	306,293	302,527
Treasury shares at cost (5,445,350 shares at September 30, 2018 and 5,367,755 shares at December 31, 2017)	(128,953)	(128,583)
Retained earnings	(38,332)	49,433
Total shareholders' equity	140,237	224,600
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 304,261	$ 381,453

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 September 30,		Nine Months Ended September 30,	
	2018 (unaudited)	2017	2018 (unaudited)	2017
REVENUES:				
Oil and condensate sales	$ 8,558	$ 6,109	$ 26,976	$ 18,134
Natural gas sales	7,128	9,681	21,585	31,956
Natural gas liquids sales	3,822	3,040	9,832	8,440
Total revenues	19,508	18,830	58,393	58,530
EXPENSES:				
Operating expenses	6,382	7,041	19,787	20,203
Exploration expenses	425	315	1,288	690
Depreciation, depletion and amortization	12,853	11,193	32,836	35,678
Impairment and abandonment of oil and gas properties	72,524	84	76,628	1,515
General and administrative expenses	6,724	6,219	18,804	18,648
Total expenses	98,908	24,852	149,343	76,734
OTHER INCOME (EXPENSE):				
Gain (loss) from investment in affiliates, net of income taxes	(270)	525	(38)	2,475
Gain (loss) from sale of assets	498	(184)	11,315	2,336
Interest expense	(1,411)	(1,138)	(4,082)	(2,822)
Gain (loss) on derivatives, net	(1,319)	(9)	(4,961)	4,574
Other income (expense)	357	—	1,239	(27)
Total other income (expense)	(2,145)	(806)	3,473	6,536
NET LOSS BEFORE INCOME TAXES	(81,545)	(6,828)	(87,477)	(11,668)
Income tax benefit (provision)	21	(88)	(288)	(397)
NET LOSS	$ (81,524)	$ (6,916)	$ (87,765)	$ (12,065)
NET LOSS PER SHARE:				
Basic	$ (3.26)	$ (0.28)	$ (3.52)	$ (0.49)
Diluted	$ (3.26)	$ (0.28)	$ (3.52)	$ (0.49)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic	25,001	24,708	24,910	24,662
Diluted	25,001	24,708	24,910	24,662

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)

	Nine Months Ended September 30, 2018	2017
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (87,765)	$ (12,065)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	32,836	35,678
Impairment of natural gas and oil properties	76,175	1,400
Exploration recovery	—	(232)
Gain on sale of assets	(11,315)	(2,336)
Loss (gain) from investment in affiliates	38	(2,475)
Stock-based compensation	3,772	4,560
Unrealized loss (gain) on derivative instruments	2,551	(3,797)
Changes in operating assets and liabilities:		
Decrease in accounts receivable & other receivables	355	4,767
Decrease in prepaids	702	1
Decrease in inventory	—	123
Increase (decrease) in accounts payable & advances from joint owners	3,571	(1,744)
Increase in other accrued liabilities	964	2,461
Increase (decrease) in income taxes payable, net	208	(308)
Other	3,051	72
Net cash provided by operating activities	$ 25,143	$ 26,105
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	$ (43,223)	$ (51,937)
Additions to furniture & equipment	—	(42)
Sale of furniture & equipment	—	12
Sale of oil & gas properties	21,562	1,151
Sale of energy credits	497	—
Net cash used in investing activities	$ (21,164)	$ (50,816)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	$ 182,319	$ 172,015
Repayments under credit facility	(185,928)	(147,143)
Purchase of treasury stock	(370)	(161)
Net cash provided by (used in) financing activities	$ (3,979)	$ 24,711
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ —	$ —
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		Additional Paid-in	Treasury	Retained	Total Shareholders'
	Shares	Amount	Capital	Stock	Earnings	Equity
	(unaudited)					
Balance at December 31, 2017	25,505,715	$ 1,223	$ 302,527	$ (128,583)	$ 49,433	$ 224,600
Treasury shares at cost	(77,595)	—	—	(370)	—	(370)
Restricted shares activity	155,988	6	(6)	—	—	—
Stock-based compensation	—	—	3,772	—	—	3,772
Net loss	—	—	—	—	(87,765)	(87,765)
Balance at September 30, 2018	25,584,108	$ 1,229	$ 306,293	$ (128,953)	$ (38,332)	$ 140,237

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, increase production from and acquire crude oil and natural gas properties in West Texas, the onshore Texas Gulf Coast and the Rocky Mountain regions of the United States.

The following table lists the Company's primary producing areas as of September 30, 2018:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Southern Delaware Basin, Pecos County, Texas	Wolfcamp
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Other Texas Gulf Coast	Conventional and smaller unconventional formations
Zavala and Dimmit counties, Texas	Buda / Eagle Ford
Weston County, Wyoming	Muddy Sandstone
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 all periods shown in this report.

The Company's 2018 capital program has focused on the development of its 15,500 gross (6,600 net) acres in the Southern Delaware Basin. 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 and assuming the Company has adequate capital to do so, through acquisition. Due to the increasing uncertainty surrounding the availability of takeaway capacity in the Permian Basin (the "Basin"), the resulting increase in negative oil and natural gas price differentials in the Basin, and pending the Company's review of liquidity-enhancing options, the Company has decided to temporarily reduce its emphasis on developmental drilling and will instead concentrate on preserving its leased acreage position by addressing lease expirations through lease extensions and/or drilling, where necessary, and reducing outstanding debt through a reduction in general and administrative costs and non-core asset rationalization. The Company continuously monitors the commodity price environment, including its stability, forecast and geographic price differentials, and, if warranted, will make adjustments to its capital program as the year progresses. The Company also continues to evaluate new organic opportunities for growth and will continue to evaluate pursuing stressed or distressed acquisition opportunities that may arise in the current commodity price environment. Acquisition efforts will be focused on areas in which the Company can leverage its geological and operational experience and expertise to exploit identified drilling opportunities and where it can develop an inventory of additional drilling prospects that the Company believes will enable it to economically grow production and add reserves.

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, 2017 (the "2017 Form 10-K") filed with the Securities and Exchange Commission ("SEC"). Please refer to the notes to the financial statements included in the 2017 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

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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 2017 Form 10-K. These unaudited interim consolidated results of operations for the nine months ended September 30, 2018 are not necessarily indicative of the results that may be expected for the year ending December 31, 2018.

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 the Company's wholly owned subsidiary, Contaro Company, is accounted for using the equity method of accounting, and therefore, the Company does not include its share of individual operating results or production in those reported for the Company's consolidated results of operations.

Liquidity and Going Concern

Over the past few months, the Company has been in discussions with its current lenders and other sources of capital regarding a possible refinancing and/or replacement of its existing RBC Credit Facility, which matures on October 1, 2019. The refinancing or replacement of the RBC Credit Facility could be made in conjunction with an issuance of unsecured or non-priority secured debt or preferred or common equity, non-core property monetization, potential monetization of certain midstream and/or water handling facilities, etc. or a combination of the foregoing. These discussions have included a possible new, replacement or extended credit facility that would be expected to provide additional borrowing capacity for future capital expenditures. There is no assurance, however, that such discussions will result in a refinancing of the RBC Credit Facility on acceptable terms, if at all, or provide any specific amount of additional liquidity for future capital expenditures. Without any further extension of the RBC Credit Facility, it will be reflected as a current liability on the Company's December 31, 2018 balance sheet, which may further limit its access to capital. These conditions raise substantial doubt about the Company's ability to continue as a going concern. However, the accompanying financial statements have been prepared assuming the Company will continue to operate as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The accompanying financial statements do not include adjustments that might result from the outcome of the uncertainty, including any adjustments to reflect the possible future effects of the recoverability and classification of recorded asset amounts or amounts and classifications of liabilities that might be necessary should the Company be unable to continue as a going concern. Management has concluded that their plans alleviate the substantial doubt about the Company's ability to continue as a going concern.

Oil and Gas Properties - Successful Efforts

The Company's application of the successful efforts method of accounting for its natural gas and oil exploration and production activities requires judgment 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

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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, probable and possible 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 $72.2 million and $74.9 million in non-cash proved property impairment charges for the three and nine months ended September 30, 2018, respectively. Included in proved property impairment expense for the three and nine months ended September 30, 2018 was a $59.4 million and a $61.7 million impairment, respectively, of the carrying costs of its Gulf of Mexico properties primarily due to revised proved reserve estimates made during the quarter ended September 30, 2018 as a result of new bottom hole pressure data gathered during the planned installation of a second stage compression in the Company’s Eugene Island 11 field. The revised reserve estimates, prepared by the Company’s third party engineers, resulted in the present value, discounted at a 10% rate (“PV-10”), of its offshore reserves being reduced to a total PV-10 of $97.2 million, a decrease of $9.8 million, thereby necessitating the requirement to reduce the carrying costs of the Gulf of Mexico properties. The three and nine months ended September 30, 2018 also included an onshore proved property impairment expense of $12.8 million and $13.2 million, respectively, of which $12.8 million impairment was related to the impairment of certain of its non-core properties in Southeast Texas that were reduced to their fair value as a result of a planned sale. See Note 3 – “Acquisitions and Dispositions” for further information regarding the sale of certain non-core properties in Southeast Texas. No impairment of proved properties was recognized during the three and nine months ended September 30, 2017.

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 impairment expense of approximately $0.1 million and approximately $1.3 million for the three and nine months ended September 30, 2018, respectively, related to impairment of certain non-core unproved properties primarily due to expiring leases. The Company recognized no impairment of unproved properties for the three months ended September 30, 2017 and $1.4 million in impairment expense for the nine months ended September 30, 2017 related to the partial impairment of two unused offshore platforms that were subsequently sold.

Net Loss Per Common Share

Basic net loss per common share is computed by dividing the net loss attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net 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. Potentially dilutive securities, including unexercised stock options, performance stock units and unvested restricted stock, have not been considered when their effect would be antidilutive. For the three and nine months ended September 30, 2018, the Company excluded 561,502 and 777,725 shares or units of potentially dilutive securities, respectively, as they were antidilutive. For the three and nine months ended September 30, 2017, the Company excluded 931,666 and 908,394 shares or units of potentially dilutive securities, respectively, as they were antidilutive.

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. 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.

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Revenue Recognition

Adoption of ASC 606

As of January 1, 2018 the Company adopted Accounting Standards Codification Topic 606 – Revenue from Contracts with Customers ("ASC 606"), which supersedes the revenue recognition requirements and industry-specific guidance under Accounting Standards Codification Top 605 – Revenue Recognition ("ASC 605"). The Company adopted ASC 606 using the modified retrospective method which allows the Company to apply the new standard to all new contracts entered into after December 31, 2017 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance prior to December 31, 2017. The Company identified no material impact on its historical revenues upon initial application of ASC 606, and as such has not recognized any cumulative catch-up effect to the opening balance of the Company's shareholders' equity as of January 1, 2018. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

Revenue from Contracts with Customers

Sales of oil, condensate, natural gas and natural gas liquids ("NGLs") are recognized at the time control of the products are transferred to the customer. Based upon the Company's current purchasers' past experience and expertise in the market, collectability is probable, and there have not been payment issues with the Company's purchasers over the past year or currently. Generally, the Company's gas processing and purchase agreements indicate that the processors take control of the gas at the inlet of the plant and that control of residue gas is returned to the Company at the outlet of the plant. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs. The Company delivers oil and condensate to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product.

When sales volumes exceed the Company's entitled share, a production imbalance occurs. If production imbalance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. Production imbalances have not had and currently do not have a material impact on the financial statements, and this did not change with the adoption of ASC 606.

Transaction Price Allocated to Remaining Performance Obligations

Generally, the Company's contracts have an initial term of one year or longer but continue month to month unless written notification of termination in a specified time period is provided by either party to the contract. The Company has used the practical expedient in ASC 606 which states that the Company is not required to disclose that transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligation is not required.

Contract Balances

The Company receives purchaser statements from the majority of its customers but there are a few contracts where the Company prepares the invoice. Payment is unconditional upon receipt of the statement or invoice. Accordingly, the Company’s product sales contracts do not give rise to contract assets or liabilities under ASC 606. The majority of the Company’s contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and supply and demand conditions. The price of these commodities fluctuates to remain competitive with supply.

Prior Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. Settlement statements may not be received for 30 to 90 days after the date production is delivered, and therefore the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. Differences between the Company’s estimates and the actual amounts received for product sales are generally recorded in the following month that payment is received. Any differences between the Company’s revenue estimates

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and actual revenue received historically have not been significant. The Company has internal controls in place for its revenue estimation accrual process.

Impact of Adoption of ASC 606

The Company has reviewed all of its natural gas, NGLs, residue gas, condensate and crude oil sales contracts to assess the impact of the provisions of ASC 606. Based upon the Company's review, there were no required changes to the recording of residue gas or condensate and crude oil contracts. Certain NGL and natural gas contracts would require insignificant changes to the recording of transportation, gathering and processing fees as net to revenue or as an expense. The Company concluded that these minor changes were not material to its operating results on a quantitative or qualitative basis. Therefore, there was no impact to its results of operations for the nine months ended September 30, 2018. The Company has modified procedures to its existing internal controls relating to revenue by reviewing for any significant increase in sales level, primarily on gas processing or gas purchasing contracts, on a quarterly basis to monitor the significance of gross revenue versus net revenue and expenses under ASC 606. As under previous revenue guidance, the Company will continue to review all new or modified revenue contracts on a quarterly basis for proper treatment.

Recent Accounting Pronouncements

Leases: In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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 treatment of leases and that proposed in ASU 2016-02 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 has commenced analyzing its leases for evaluation and will continue to assess the impact this may have on its financial position, results of operations and cash flows.

In January 2018, the FASB issued ASU 2018-01 – Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. The amendments in ASU 2018-01 permit an entity to elect an optional transition practical expedient to not evaluate under Topic 842 land easements (right of way payments) that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840. Right of way payments do not have a material impact on the Company's results of operations and the Company plans to elect the practical expedient to evaluate right of way payments prospectively on adoption of Topic 842.

In July 2018, the FASB issued ASU 2018-10 – Codification Improvements to Topic 842, Leases. The amendments in ASU 2018-10 affect narrow aspects of the guidance issued in the amendments in ASU 2016-02 – Leases (Topic 842). For public entities, ASU 2018-10 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 is currently evaluating the provisions of this update and assessing the impact, if any, it may have on its financial position and results of operations.

In July 2018, the FASB issued ASU 2018-11 – Leases (Topic 842) Targeted Improvements. The FASB has been assisting stakeholders with implementation questions and issues as organizations prepare to adopt ASU 2016-02. Many stakeholders inquired about the following two requirements: Comparative reporting requirements for initial adoption and, for lessors only, separating lease and non-lease components in a contract and allocating the consideration in the contract to the separate components. The amendments in ASU 2018-11 provide another transition method in addition to the existing transition method by allowing entities to initially apply the new leases standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The amendments in ASU 2018-11 provide lessors with a practical expedient, by class of underlying asset, to not separate non-lease components from the associated lease component. The Company is currently evaluating the provisions of this update and assessing the impact, if any, it may have on its financial position and results of operations.

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Other: In August 2018, the FASB issued ASU 2018-13 – Fair Value Measurement (Topic 820). The amendments in ASU 2018-13 modify the disclosure requirements on fair value measurements in Topic 820. The amendments in this update are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The provisions of this update are not expected to have a material impact on the Company's financial position or results of operations.

3. Acquisitions and Dispositions

On September 11, 2018, the Company entered into a definitive agreement to divest certain of its non-core assets in Liberty and Hardin Counties in Southeast Texas. These assets held for sale are recorded at the lower of their carrying value or fair value less cost to sell. As a result of this planned sale, the Company reduced the value of the assets to their fair value and recorded an impairment of approximately $12.8 million during the three months ended September 30, 2018 in "Impairment and abandonment of oil and gas properties" in the Company's consolidated statement of operations. The sale was completed on November 2, 2018 for cash proceeds of $6.0 million. This planned disposition did not qualify as a discontinued operation.

The major categories of assets and liabilities for these assets held for sale were:

	September 30, 2018 (in thousands)	
Assets classified as held for sale:		
Accounts receivable	$	1,748
Property and equipment, at cost:		
Oil and natural gas properties; successful efforts method		46,855
Accumulated depreciation, depletion and impairment		(38,607)
Property and equipment, net		8,248
Total assets classified as held for sale	$	9,996
Liabilities associated with assets held for sale:		
Current liabilities:		
Revenue payable	$	(784)
Accrued liabilities		(580)
Current asset retirement obligations		(76)
Total current liabilities		(1,440)
Asset retirement obligations		(2,155)
Total liabilities associated with assets held for sale	$	(3,595)

On May 25, 2018, the Company sold its non-operated assets located in Starr County, Texas for a cash purchase price of $0.6 million. The Company recorded a net gain of $1.3 million after removal of the asset retirement obligations associated with the sold properties and final closing adjustments.

On March 28, 2018, the Company sold its operated Eagle Ford Shale assets located in Karnes County, Texas for a cash purchase price of $21.0 million. The Company recorded a net gain of $9.5 million, after final closing adjustments.

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 Topic 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

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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 September 30, 2018. As required by ASC 820, a financial instrument's 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 September 30, 2018 (in thousands):

	Total	Fair Value Measurements Using		
	Carrying Value	Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts - assets	$ 82	$ —	$ 82	$ —
Commodity price contracts - liabilities	$ (3,877)	$ —	$ (3,877)	$ —

Derivatives listed above are recorded in "Current derivative asset or liability" 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 its 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 reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted market prices and implied volatility factors related to changes in the forward curves. See Note 5 - "Derivative Instruments" for additional discussion of derivatives.

As of September 30, 2018, the Company's derivative contracts were all with certain members of its credit facility lending 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 Accounting Standards Codification Topic 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 nine months. See Note 9 - "Long-Term Debt" for further information.

Impairments

The Company 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, probable and possible 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. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3.

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 September 30, 2018, 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.

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As of September 30, 2018, the following derivative instruments were in place (fair value in thousands):

Commodity	Period	Derivative	Volume/Month	Price/Unit	Fair Value
Natural Gas	Oct 2018	Swap	70,000 MMBtus	$ 3.07 (1)	3
Natural Gas	Nov 2018 - Dec 2018	Swap	320,000 MMBtus	$ 3.07 (1)	14
Oil	Oct 2018	Collar	20,000 Bbls	$ 52.00 - 56.85 (2)	(479)
Oil	Nov 2018 - Dec 2018	Collar	15,000 Bbls	$ 52.00 - 56.85 (2)	(680)
Oil	Oct 2018 - Dec 2018	Collar	2,000 Bbls	$ 52.00 - 58.76 (3)	(86)
Oil	Nov 2018 - Dec 2018	Collar	5,000 Bbls	$ 58.00 - 68.00 (2)	(118)
Oil	Oct 2018	Swap	3,000 Bbls	$ 70.11 (3)	(9)
Oil	Nov 2018 - Dec 2018	Swap	6,000 Bbls	$ 70.11 (3)	(33)
Oil	Jan 2019 - Dec 2019	Collar	4,000 Bbls	$ 52.00 - 59.45 (3)	(601)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$ 50.00 - 58.00 (2)	(1,565)
Oil	Jan 2019 - July 2019	Swap	6,000 Bbls	$ 66.10 (3)	(241)
		Total net fair value of derivative instruments			$ (3,795)

(1) Based on Henry Hub NYMEX natural gas prices.
(2) Based on Argus Louisiana Light Sweet crude oil prices.
(3) Based on West Texas Intermediate crude oil prices.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of September 30, 2018 (in thousands):

	Gross	Netting (1)	Total
Assets	$ 82	$ —	$ 82
Liabilities	$ (3,877)	$ —	$ (3,877)

(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, 2017 (in thousands):

	Gross	Netting (1)	Total
Assets	$ 1,188	$ (1,188)	$ —
Liabilities	$ (2,431)	$ 1,188	$ (1,243)

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

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The following table summarizes the effect of derivative contracts on the consolidated statements of operations for the three and nine months ended September 30, 2018 and 2017 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Crude oil contracts	$ (1,136)	$ 342	$ (2,846)	$ 879
Natural gas contracts	57	179	436	(102)
Realized gain (loss)	$ (1,079)	$ 521	$ (2,410)	$ 777
Crude oil contracts	$ (152)	$ (661)	$ (1,747)	$ 156
Natural gas contracts	(88)	131	(804)	3,641
Unrealized gain (loss)	$ (240)	$ (530)	$ (2,551)	$ 3,797
Gain (loss) on derivatives, net	$ (1,319)	$ (9)	$ (4,961)	$ 4,574

In October 2018, the Company entered into the following additional derivative contracts with certain members of its credit facility lenders:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Natural Gas	Nov 2018 - Dec 2018	Swap	200,000 MMBtus	$ 3.35 (1)
Natural Gas	Nov 2018 - Dec 2018	Swap	100,000 MMBtus	$ 3.21 (1)
Natural Gas	Jan 2019 - Mar 2019	Swap	600,000 MMBtus	$ 3.21 (1)
Natural Gas	Apr 2019 - July 2019	Swap	600,000 MMBtus	$ 2.75 (1)
Natural Gas	Aug 2019 - Oct 2019	Swap	100,000 MMBtus	$ 2.75 (1)
Natural Gas	Nov 2019 - Dec 2019	Swap	500,000 MMBtus	$ 2.75 (1)
Oil	Nov 2018 - Dec 2018	Collar	7,000 Bbls	$ 70.00 - 77.65 (2)
Oil	Jan 2019 - June 2019	Collar	12,000 Bbls	$ 70.00 - 76.25 (2)
Oil	July 2019	Swap	12,000 Bbls	$ 72.10 (2)
Oil	Aug 2019 - Oct 2019	Swap	9,000 Bbls	$ 72.10 (2)
Oil	Nov 2019 - Dec 2019	Swap	12,000 Bbls	$ 72.10 (2)

(1) Based on Henry Hub NYMEX natural gas prices.
(2) Based on West Texas Intermediate crude oil prices.

6. Stock-Based Compensation

The Company recognized approximately $3.8 million and $4.6 million in stock compensation expense during the nine months ended September 30, 2018 and 2017, respectively, for equity awards granted to its officers, employees and directors. As of September 30, 2018, an additional $2.6 million of compensation expense remained to be recognized over the remaining weighted-average vesting period of 1.4 years. This includes expense related to restricted stock, Performance Stock Units (“PSUs”) and stock options.

Restricted Stock

During the nine months ended September 30, 2018, the Company granted 225,782 shares of restricted common stock, which vest over three years, to executive officers as part of their overall compensation package. Additionally, the Company granted 82,500 shares of restricted common stock, which vest over one year, to directors pursuant to the Company’s Director Compensation Plan. The weighted average fair value of the restricted shares granted during the nine months ended September 30, 2018, was $3.76 per share with a total fair value of approximately $1.2 million with no adjustment for an estimated weighted average forfeiture rate. During the nine months ended September 30, 2018, 152,294 restricted shares were forfeited by former employees, of which 105,800 were related to the resignation of the Company’s former President and CEO in September 2018. The aggregate intrinsic value of restricted shares forfeited

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during the nine months ended September 30, 2018 was approximately $1.0 million. Approximately 1.5 million shares remained available for grant under the Amended and Restated 2009 Incentive Compensation Plan as of September 30, 2018, assuming PSUs are settled at 100% of target.

During the nine months ended September 30, 2017, the Company granted 383,376 shares of restricted common stock, which vest over three years, to new and existing employees as part of their overall compensation package and 74,325 shares of restricted common stock, which vest over one year, to directors pursuant to the Company’s Director Compensation Plan. The weighted average fair value of the restricted shares granted during the nine months ended September 30, 2017, was $7.55 per share with a total fair value of approximately $3.5 million after adjustment for an estimated weighted average forfeiture rate of 5.7%. During the nine months ended September 30, 2017, 128,615 restricted shares were forfeited by former employees. The aggregate intrinsic value of restricted shares forfeited during the nine months ended September 30, 2017 was approximately $1.3 million.

Performance Stock Units

During the nine months ended September 30, 2018, the Company granted 190,782 PSUs to executive officers as part of their overall compensation package, at a weighted average fair value of $7.69 per unit. During the nine months ended September 30, 2017, the Company granted 30,000 PSUs to a new employee, at a weighted average fair value of $8.32 per unit. 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 during the nine months ended September 30, 2017. All fair value prices were determined using the Monte Carlo simulation model. During the nine months ended September 30, 2018 and 2017, 182,227 and 94,063 PSUs were forfeited by former employees, respectively. 153,127 of the PSU forfeitures in 2018 were related to the resignation of the Company’s former President and CEO in September 2018. 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.

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 nine months ended September 30, 2018 and 2017, 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 nine months ended September 30, 2018 or 2017.

During the nine months ended September 30, 2018, no stock options were exercised and 4,500 were forfeited by former employees. During the nine months ended September 30, 2017, no stock options were exercised and stock options for 17,072 shares of common stock were forfeited by former employees.

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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):

	September 30, 2018	December 31, 2017
Accounts receivable:		
Trade receivables	$ 4,908	$ 6,565
Receivable for Alta Resources distribution	1,993	1,993
Joint interest billings	3,649	4,030
Income taxes receivable	424	424
Other receivables	764	828
Allowance for doubtful accounts	(781)	(781)
Total accounts receivable	$ 10,957	$ 13,059
Prepaid expenses and other:		
Prepaid insurance	$ 874	$ 1,177
Other	317	715
Total prepaid expenses and other	$ 1,191	$ 1,892
Accounts payable and accrued liabilities:		
Royalties and revenue payable	$ 19,804	$ 18,181
Advances from partners	4,104	2,243
Accrued exploration and development	11,164	8,400
Trade payables	7,917	9,559
Accrued general and administrative expenses	3,019	2,960
Accrued operating expenses	1,557	1,654
Other accounts payable and accrued liabilities	5,334	3,758
Total accounts payable and accrued liabilities	$ 52,899	$ 46,755

Included in the table below is supplemental cash flow disclosures and non-cash investing activities during the nine months ended September 30, 2018 and 2017 (in thousands):

	Nine Months Ended September 30,	
	2018	2017
Cash payments:		
Interest payments	$ 3,846	$ 2,501
Income tax payments	$ 81	$ 708
Non-cash investing activities in the consolidated statements of cash flows:		

Increase (decrease) in accrued capital expenditures	$ 2,764	$ (10,142)

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 unaudited condensed balance sheet data for Exaro as of September 30, 2018 and December 31, 2017. The balance sheet data was derived from Exaro's balance sheet as of September 30, 2018 and December 31, 2017 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 September 30, 2018 was approximately $18.3 million.

	September 30, 2018	December 31, 2017
Current assets (1)	$ 13,112	$ 17,063
Non-current assets:		
Net property and equipment	75,769	82,450
Gas processing deposit	1,150	1,150
Other non-current assets	8	390
Total non-current assets	76,927	83,990
Total assets	$ 90,039	$ 101,053
Current liabilities (2)	$ 35,335	$ 6,199
Non-current liabilities:		
Long-term debt	—	40,375
Other non-current liabilities	4,381	3,858
Total non-current liabilities	4,381	44,233
Members' equity	50,323	50,621
Total liabilities & members' equity	$ 90,039	$ 101,053

(1) Approximately $10.5 million and $12.8 million of current assets as of September 30, 2018 and December 31, 2017, respectively, is cash.
(2) Approximately $30.2 million of current liabilities as of September 30, 2018 is the senior loan facility maturing September 26, 2019.

The following table (in thousands) presents the unaudited condensed results of operations for Exaro for the three and nine months ended September 30, 2018 and 2017. The results of operations for the three and nine months ended September 30, 2018 and 2017 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 September 30, 2018 and 2017 was a loss of $0.3 million, net of no tax expense, and a gain of $0.5 million, net of no tax expense, respectively. The Company's share in Exaro's results of operations recognized for the nine months ended September 30, 2018 and 2017 was a loss of $38,000, net of no tax expense, and a gain of $2.5 million, net of no tax expense, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Production:				
Oil (thousand barrels)	17	24	60	77

Gas (million cubic feet)	1,882	2,216	5,763	6,797
Total (million cubic feet equivalent)	1,984	2,360	6,123	7,260
Oil and natural gas sales	$ 6,153	$ 7,483	$ 18,991	$ 24,499
Gain (loss) on derivatives	(867)	318	178	3,720
Less:				
Lease operating expenses	3,094	2,928	9,763	10,914
Depreciation, depletion, amortization & accretion	2,502	2,143	7,230	6,734
General & administrative expense	454	701	1,159	2,308
Income (loss) from continuing operations	(764)	2,029	1,017	8,263
Net interest expense	(470)	(629)	(1,550)	(1,582)
Net income (loss)	$ (1,234)	$ 1,400	$ (533)	$ 6,681

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

The Company’s $500 million revolving credit facility with Royal Bank of Canada and other lenders (the “RBC Credit Facility”) currently expires on October 1, 2019. The borrowing base under the facility is redetermined each November and May. As of September 30, 2018, the borrowing base under the RBC Credit Facility was $105 million. On November 2, 2018, the Company entered into the Sixth Amendment to the RBC Credit Facility (the “Sixth Amendment”), whereby the current borrowing base was reaffirmed at $105 million and will be reduced to $90 million on and after January 31, 2019, unless such reduction is waived by all lenders. Any excess of borrowings and letter of credit obligations outstanding after January 31, 2019 over such reduced borrowing base will be due and payable on or prior to March 1, 2019.

The Sixth Amendment also provides for, among other things: (i) reducing the letter of credit issuance commitment capacity from $20.0 million to $5.0 million; (ii) waiving compliance with the required minimum 1.00 to 1.00 Current Ratio for the fiscal quarters ended September 30, 2018 and December 31, 2018; (iii) eliminating an exception from the restriction on payment of dividends, stock repurchases or redemptions of equity for repurchases under certain circumstances; (iv) waiving advance notice and a requirement for delivery of a revised reserve report related to the Liberty and Hardin County, Texas asset sale; and (v) requires delivery to the administrative agent of internally-prepared monthly consolidated financial statements of the Company within 25 days of the end of such month. See Part II – Item 5 “Other Information” for additional discussion of the Sixth Amendment.

As of September 30, 2018, the Company had approximately $81.8 million outstanding under the RBC Credit Facility and $1.9 million in outstanding letters of credit. As of December 31, 2017, the Company had approximately $85.4 million outstanding under the RBC Credit Facility and $1.9 million in outstanding letters of credit. As of September 30, 2018, borrowing availability under the RBC Credit Facility was $21.3 million.

The RBC Credit Facility is collateralized by a lien on substantially all the producing assets of the Company and its subsidiaries, including a security interest in the stock of Contango’s subsidiaries and a lien on the Company’s oil and gas properties.

Total interest expense under the RBC Credit Facility, including commitment fees, for the three and nine months ended September 30, 2018 was approximately $1.4 million and $4.1 million, respectively. Total interest expense under the RBC Credit Facility, including commitment fees, for the three and nine months ended September 30, 2017 was approximately $1.1 million and $2.8 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 at least 1.00 to 1.00 and a Leverage Ratio of not more than 3.50 to 1.00, both as defined in the RBC Credit Facility Agreement. As of September 30, 2018, the Company was in compliance with all but the Current Ratio covenant under the RBC Credit Facility. The Company obtained a waiver for such non-compliance effective for September 30, 2018 and December 31, 2018 under the Sixth Amendment. The RBC Credit Facility 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 including the current ratio covenant, bankruptcy, insolvency or change of control events.

The weighted average interest rate in effect at September 30, 2018 and December 31, 2017 was 6.0% and 5.2%, respectively. The RBC Credit Facility matures on October 1, 2019, at which time any outstanding borrowings and an amount equal to any outstanding letters of credit obligations will be due.

Pursuit of Refinancing and Other Liquidity-Enhancing Alternatives

Over the past few months, the Company has been in discussions with its current lenders and other sources of capital regarding a possible refinancing and/or replacement of its existing RBC Credit Facility, which matures on October 1, 2019. There is no assurance, however, that such discussions will result in a refinancing of the RBC Credit Facility on acceptable terms, if at all, or provide any specific amount of additional liquidity for future capital expenditures, and in such case there could be substantial doubt that the Company could continue as a going concern. The refinancing and/or replacement of the RBC Credit Facility could be made in conjunction with an issuance of unsecured

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or non-priority secured debt or preferred or common equity, non-core property monetization, potential monetization of certain midstream and/or water handling facilities, etc. or a combination of the foregoing. These discussions have included a possible new, replacement or extended credit facility that would be expected to provide additional borrowing capacity for future capital expenditures. While the Company reviews such liquidity-enhancing alternative sources of capital, it intends to continue to minimize its drilling program capital expenditures in the Southern Delaware Basin and pursue a reduction in its borrowings under the RBC Credit Facility, including through a reduction in cash general and administrative expenses and the possible sale of additional non-core properties.

10. Income Taxes

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Current tax provision (benefit):				
Federal	$ —	$ —	$ —	$ —
State	(21)	88	288	397
Total	$ (21)	$ 88	$ 288	$ 397
Total tax provision (benefit):				
Federal	$ —	$ —	$ —	$ —
State	(21)	88	288	397
Total income tax provision (benefit)	$ (21)	$ 88	$ 288	$ 397

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 nine months ended September 30, 2018, the Company continued to take a full valuation allowance against its deferred tax asset except for the portion attributable to the estimated refundable Alternative Minimum Tax ("AMT") credit. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

On December 22, 2017, the United States enacted tax reform legislation known as the H.R.1, commonly referred to as the "Tax Cuts and Jobs Act" (the "Act"), resulting in significant modifications to existing law. The Company completed the accounting for the effects of the Act during 2017. The Company's financial statements for the nine months ended

September 30, 2018 reflect certain effects of the Act which includes the reduced corporate tax of 21%, elimination of the corporate AMT, limitations on the use of interest expense and net operating losses, accelerated expensing of tangible property, as well as other changes.

11. 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 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 appealed the trial court’s decision to the applicable state Court of Appeals. In the fourth quarter of 2017, the Court of Appeals issued its opinion and affirmed the trial court’s summary decision. In the first quarter of 2018, the Company

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filed a motion for rehearing with the Court of Appeals, which was denied, as expected. The Company continues to vigorously defend this lawsuit and has filed a petition requesting a review by the Texas Supreme Court, as the Company believes the trial and appellate courts erred in the interpretation of the law. The Company is awaiting a response from the Texas Supreme Court as to whether it intends to review the case. In addition, the Company is also in the process of seeking amicus briefs from industry associations whose members would be affected by the Court of Appeals' ruling.

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 appealed the trial court's decision to the applicable state Court of Appeals. On December 14, 2017, the Court of Appeals affirmed the judgment in the Company's favor. The plaintiff filed a motion for rehearing, which was denied in May 2018. The plaintiff has filed a petition requesting that the matter be reviewed by the Texas Supreme Court; the parties are awaiting a response from the Texas Supreme Court as to whether it intends to review the case. The Company continues to vigorously defend 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.

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. As of September 30, 2018, the Company estimates that the net deficiency fee will be approximately $1.0 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 September 30, 2018, based upon the current commodity price market and the Company's short term strategic drilling plans, the Company has recorded a $1.5 million loss contingency through September 30, 2019.

12. Subsequent Events

On September 11, 2018, the Company entered into a definitive agreement to divest certain of its non-core assets in Liberty and Hardin Counties in Southeast Texas. As a result of this planned sale, the Company reduced the value of the assets to their fair value and recorded an impairment of approximately $12.8 million during the three months ended September 30, 2018 in "Impairment and abandonment of oil and gas properties" in the Company's consolidated statement of operations. The sale was completed on November 2, 2018 for cash proceeds of $6.0 million. See Note 3 – "Acquisitions and Dispositions" for further information regarding the sale of these non-core properties in Southeast Texas.

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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”, “will”, “believe”, “plan”, “intend”, “expect”, “anticipate”, “estimate”, “forecast”, “goal” and similar exp 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 Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 and those factors summarized below:

- our ability to successfully develop our undeveloped acreage in the Southern Delaware Basin and realize the benefits associated therewith;
- our financial position;
- our business strategy, including execution of any changes in our strategy;
- meeting our forecasts and budgets;
- expectations regarding natural gas and oil markets in the United States;
- volatility in natural gas, natural gas liquids and oil prices, including regional differentials;
- 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 acting as operator of deep high pressure and high 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;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations, and fund our drilling program;

- our ability to comply with financial covenants in our debt instruments, repay indebtedness and access new sources of indebtedness;
- the cost and availability of rigs and other materials, services and operating equipment;
- timely and full receipt of sale proceeds from the sale of our production;
- our ability to find, acquire, market, develop and produce new natural gas and oil properties;
- interest rate volatility;
- our ability to complete strategic dispositions of assets and realize the benefits of such dispositions;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- the need to take impairments on our properties due to lower commodity prices;
- the ability to post additional collateral for current bonds or comply with new supplemental bonding requirements imposed by the Bureau of Ocean Energy Management;
- 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;

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- 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 retain key members of senior management and key technical employees and to find and retain skilled personnel;
- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals (including additional taxes and changes in environmental regulations);
- worldwide economic conditions;
- the ability to construct and operate infrastructure, including pipeline and production facilities;
- 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;
- the ability to obtain adequate insurance coverage on commercially reasonable terms; and
- the limited trading volume of our common stock and general market volatility.

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. You should not place undue reliance on forward-looking statements in this report as they 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.

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 2017 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, increase production from and acquire crude oil and natural gas properties in West Texas, the onshore Texas Gulf Coast and the Rocky Mountain regions of the United States.

The following table lists our primary producing areas as of September 30, 2018:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Southern Delaware Basin, Pecos County, Texas	Wolfcamp
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Other Texas Gulf Coast	Conventional and smaller unconventional formations
Zavala and Dimmit counties, Texas	Buda / Eagle Ford
Weston County, Wyoming	Muddy Sandstone
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 all periods shown in this report.

Capital Expenditures

Our 2018 capital program has focused on the development of our 15,500 gross (6,600 net) acres in the Southern Delaware Basin. Additionally, we plan to 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 and assuming we have adequate capital to do so, through acquisition.

Despite challenges experienced throughout the Southern Delaware Basin related to constrained production takeaway capacity, and the adverse impact on commodity price differentials, we still generate positive returns to date on our drilling investment. However, due to the increasing uncertainty surrounding the availability of takeaway capacity in the Permian Basin (the "Basin"), the resulting increase in negative oil and natural gas price differentials for production from the Basin compared to benchmark West Texas Intermediate spot prices quoted at the Cushing and Oklahoma oil hub and our pending review of liquidity-enhancing options, we have decided to reduce our emphasis on developmental drilling in the fourth quarter and will instead concentrate on preserving our leased acreage by addressing lease expirations through lease extensions and/or drilling, where necessary, and reducing debt outstanding through a reduction in general and administrative costs and non-core asset rationalization. We continuously monitor the commodity price environment, including its stability, forecast and geographic price differentials, and, if warranted, will make adjustments to our capital program as the year progresses. We also continue to evaluate new organic opportunities for growth and will continue to evaluate pursuing stressed or distressed acquisition opportunities that may arise in the current commodity price environment. Acquisition efforts will be focused on areas in which we can leverage our geological and operational experience and expertise to exploit identified drilling opportunities and where we can develop an inventory of additional drilling prospects that we believe will enable us to economically grow production and add reserves.

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Southern Delaware Basin

Our first five Southern Delaware Basin wells in Pecos County, Texas were brought on production during 2017. During the nine months ended September 30, 2018, we brought six additional wells on production as follows:

Well Name	Formation	First Production	IP 30 (BOED)	% Oil	WI %	NRI %	TMD (feet)	Lateral (feet)
Ragin Bull 3H	Wolfcamp A	Jan 2018	1,070	67 %	49 %	37 %	20,570	10,325
River Rattler 1H	Wolfcamp B	March 2018	1,225	74 %	44 %	33 %	20,710	10,275
Ragin Bull 2H	Wolfcamp B	April 2018	734	66 %	49 %	37 %	20,625	10,334
Sidewinder 1H	Wolfcamp A	July 2018	368	70 %	49 %	37 %	20,550	10,500
Gunner 3H	Wolfcamp B	July 2018	773	78 %	47 %	35 %	20,167	10,067
Fighting Ace 2H	Wolfcamp A	Sept 2018	656	71 %	50 %	38 %	20,560	10,598

On August 2, 2018, we spud the General Paxton #1H (50% WI, 38% NRI) in the southeast quadrant of our acreage position. This well targeted the Wolfcamp A formation and was drilled to a total measured depth (“TMD”) of approximately 20,145 feet, including a lateral of approximately 10,392 feet, and had a 24-hour IP of 1,129 Boed (81% oil) and a 30-day IP of 981 Boed (79% oil).

On August 31, we spud the Ripper State #2H (50% WI, 38% NRI) targeting the Wolfcamp B formation. This well was drilled to a TMD of approximately 20,545 feet, including a lateral of approximately 10,179 feet. Completion operations will begin at a later date.

The River Rattler #1H, our first Wolfcamp B test, has had the best 24-hour IP (1,416 Boed) and 30-day IP of all our wells in the Southern Delaware Basin, while the General Paxton #1H has the highest oil cut than any other well.

For the remainder of 2018, we intend to reduce our emphasis on drilling while the Midland-Cushing oil price differential in the region stabilizes and will use this time to further evaluate well results and offset operator activity while infrastructure continues to develop in the area. Any further drilling during 2018 will be as necessary to maintain our Southern Delaware Basin acreage position.

Impairment of Long-Lived Assets

We recognized $72.2 million and $74.9 million in non-cash impairment of proved properties during the three and nine months ended September 30, 2018, respectively. Included in proved property impairment expense for the three and nine months ended September 30, 2018 was a $59.4 million and $61.7 million impairment, respectively, due to the impairment of carrying costs of our Gulf of Mexico properties due to revised reserve estimates made during the third quarter as a result of new bottom hole pressure data gathered during the planned installation of the second stage of compression at our Eugene Island 11 field. The revised reserve estimates, prepared by our third party engineers, resulted in the present value, discounted at a 10% rate (“PV-10”), of our offshore reserves being reduced by $9.8 million. 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. The three and nine months ended September 30, 2018 also included an onshore proved property impairment expense of $12.8 million and $13.2 million, respectively, of which $12.8 million impairment was related to the impairment of certain of our non-core properties in Southeast Texas related to reducing such properties to their fair value as a result of a planned sale. See Note 3 – “Acquisitions and Dispositions” for further information regarding the planned sale of such non-core properties in Southeast Texas. We recognized impairment expense of approximately $0.1 million and approximately $1.3 million for the three and nine months ended September 30, 2018, respectively, related to impairment of certain non-core unproved properties primarily due to expiring non-core leases.

Summary Production Information

Our production for the three months ended September 30, 2018 was approximately 62% offshore and 38% onshore, volumetrically, and was comprised of 61% natural gas, 21% oil and 18% natural gas liquids. Our production for the three months ended September 30, 2017 was 69% offshore and 31% onshore, volumetrically, and was comprised of approximately 68% natural gas, 16% 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				
	September 30, 2017	December 31, 2017	March 31, 2018	June 30, 2018	September 30, 2018
Offshore GOM					
Dutch and Mary Rose (1)	32.2	30.8	29.0	21.0	25.2
Vermilion 170	4.2	3.5	3.0	2.7	2.0
South Timbalier 17 (2)	0.1	—	—	—	—
Southeast Texas (3)	7.8	7.5	7.3	6.4	6.0
South Texas (4)	4.6	5.8	5.3	4.5	3.1
West Texas	3.2	3.2	4.5	6.7	6.4
Other (5)	1.1	1.0	0.9	1.1	0.9
	53.2	51.8	50.0	42.4	43.6

(1) Includes a decreased production rate of 4.2 Mmcfe/d due to downtime related to compressor installation and maintenance during the three months ended June 30, 2018. Our GOM production was not materially affected by Hurricane Michael which passed through the northeastern GOM in October 2018.
(2) South Timbalier 17 ceased production in August 2017.
(3) Includes Woodbine production from Madison and Grimes counties and conventional production in others.
(4) Includes Eagle Ford and Buda production from Karnes, Zavala and Dimmit counties, and conventional production in others. Includes a decreased production rate of 0.7 Mmcfe/d during the three months ended June 30, 2018 due to Karnes County sale during three months ended March 31, 2018.
(5) Includes onshore wells primarily in East Texas and Wyoming.

Other Investments

Jonah Field - Sublette County, Wyoming

Our wholly owned subsidiary, Contaro Company currently has a 37% ownership interest in Exaro. As of September 30, 2018, Exaro had 648 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 22 Mmcfe/d, net to Exaro. As a result of our investment in Exaro, we recognized an investment loss of approximately $0.3 million, net of no tax expense, for the three months ended September 30, 2018, and an investment gain of $0.5 million, net of no tax expense, for the three months ended September 30, 2017. For the nine months ended September 30, 2018 and 2017, we recognized an investment loss of approximately $38,000, net of no tax expense, and $2.5 million, net of no tax expense, respectively, as a result of our investment in Exaro. See Note 8 to our Financial Statements - “Investment in Exaro Energy III LLC” for additional details related to this investment.

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Results of Operations for the Three and Nine Months Ended September 30, 2018 and 2017

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 nine months ended September 30, 2018 and 2017. 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 operating expenses include production taxes, such as ad valorem and severance taxes.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	%	2018	2017	%
Revenues (thousands):						
Oil and condensate sales	$ 8,558	$ 6,109	40 %	$ 26,976	$ 18,134	49 %
Natural gas sales	7,128	9,681	(26) %	21,585	31,956	(32) %
NGL sales	3,822	3,040	26 %	9,832	8,440	16 %
Total revenues	$ 19,508	$ 18,830	4 %	$ 58,393	$ 58,530	(0) %
Production:						
Oil and condensate (thousand barrels)						
Offshore GOM	20	23	(13) %	56	78	(28) %
Southeast Texas	26	35	(26) %	89	117	(24) %
South Texas	13	19	(32) %	66	68	(3) %
West Texas	70	46	52 %	192	93	106 %
Other	9	9	— %	27	32	(16) %
Total oil and condensate	138	132	5 %	430	388	11 %
Natural gas (million cubic feet)						
Offshore GOM	1,943	2,702	(28) %	5,934	8,618	(31) %
Southeast Texas	260	324	(20) %	825	999	(17) %
South Texas	152	232	(34) %	584	837	(30) %
West Texas	74	11	573 %	200	45	344 %
Other	32	46	(30) %	110	151	(27) %
Total natural gas	2,461	3,315	(26) %	7,653	10,650	(28) %
Natural gas liquids (thousand barrels)						
Offshore GOM	74	87	(15) %	211	254	(17) %
Southeast Texas	22	31	(29) %	72	89	(19) %
South Texas	9	13	(31) %	33	43	(23) %
West Texas	16	1	* %	41	10	310 %
Other	—	—	— %	—	1	(100) %
Total natural gas liquids	121	132	(8) %	357	397	(10) %
Total (million cubic feet equivalent)						
Offshore GOM	2,505	3,360	(25) %	7,538	10,608	(29) %
Southeast Texas	548	721	(24) %	1,788	2,239	(20) %
South Texas	282	424	(33) %	1,173	1,507	(22) %

West Texas	591	296	100	%	1,599	655	144	%
Other	89	100	(11)	%	275	350	(21)	%
Total production	4,015	4,901	(18)	%	12,373	15,359	(19)	%
Daily Production:								
Oil and condensate (thousand barrels per day)								
Offshore GOM	0.2	0.2	(13)	%	0.2	0.3	(28)	%
Southeast Texas	0.3	0.4	(26)	%	0.3	0.4	(24)	%
South Texas	0.1	0.2	(32)	%	0.2	0.3	(3)	%
West Texas	0.8	0.5	52	%	0.7	0.3	106	%
Other	0.1	0.1	—	%	0.2	0.1	(16)	%
Total oil and condensate	1.5	1.4	5	%	1.6	1.4	11	%

	Three Months Ended September 30, 2018	2017	%	Nine Months Ended September 30, 2018	2017	%
Natural gas (million cubic feet per day)						
Offshore GOM	21.1	29.4	(28) %	21.8	31.6	(31) %
Southeast Texas	2.8	3.5	(20) %	3.0	3.7	(17) %
South Texas	1.7	2.5	(34) %	2.1	3.1	(30) %
West Texas	0.8	0.1	573 %	0.7	0.1	344 %
Other	0.3	0.5	(30) %	0.4	0.5	(27) %
Total natural gas	26.7	36.0	(26) %	28.0	39.0	(28) %
Natural gas liquids (thousand barrels per day)						
Offshore GOM	0.8	0.9	(15) %	0.8	1.0	(17) %
Southeast Texas	0.2	0.3	(29) %	0.3	0.3	(19) %
South Texas	0.1	0.1	(31) %	0.1	0.2	(23) %
West Texas	0.2	0.1	* %	0.1	—	310 %
Other	—	—	— %	—	—	(100) %
Total natural gas liquids	1.3	1.4	(8) %	1.3	1.5	(10) %
Total (million cubic feet equivalent per day)						
Offshore GOM	27.2	36.5	(25) %	27.6	38.9	(29) %
Southeast Texas	6.0	7.8	(24) %	6.5	8.2	(20) %
South Texas	3.1	4.6	(33) %	4.3	5.5	(22) %
West Texas	6.4	3.2	100 %	5.9	2.4	144 %
Other	0.9	1.1	(11) %	1.0	1.3	(21) %
Total production	43.6	53.2	(18) %	45.3	56.3	(19) %
Average Sales Price:						
Oil and condensate (per barrel)	$ 61.92	$ 46.30	34 %	$ 62.76	$ 46.76	34 %
Natural gas (per thousand cubic feet)	$ 2.90	$ 2.92	(1) %	$ 2.82	$ 3.00	(6) %
Natural gas liquids (per barrel)	$ 31.59	$ 22.98	37 %	$ 27.45	$ 21.26	29 %
Total (per thousand cubic feet equivalent)	$ 4.86	$ 3.84	27 %	$ 4.72	$ 3.81	24 %
Expenses (thousands):						
Operating expenses	$ 6,382	$ 7,041	(9) %	$ 19,787	$ 20,203	(2) %
Exploration expenses	$ 425	$ 315	35 %	$ 1,288	$ 690	87 %
Depreciation, depletion and amortization	$ 12,853	$ 11,193	15 %	$ 32,836	$ 35,678	(8) %
Impairment and abandonment of oil and gas properties	$ 72,524	$ 84	* %	$ 76,628	$ 1,515	* %
General and administrative expenses	$ 6,724	$ 6,219	8 %	$ 18,804	$ 18,648	1 %
Gain (loss) from investment in affiliates (net of taxes)	$ (270)	$ 525	(151) %	$ (38)	$ 2,475	(102) %

Selected data per Mcfe:

Operating expenses	$ 1.59	$ 1.44	10	%	$ 1.60	$ 1.32	21	%
General and administrative expenses	$ 1.67	$ 1.27	31	%	$ 1.52	$ 1.21	26	%
Depreciation, depletion and amortization	$ 3.20	$ 2.28	40	%	$ 2.65	$ 2.32	14	%

* Greater than 1,000%

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017

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.

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We reported revenues of $19.5 million for the three months ended September 30, 2018, compared to revenues of $18.8 million for the three months ended September 30, 2017. The increase in revenues was primarily attributable to higher oil and NGL prices. Oil and NGL sales were 63% of our total revenue for the three months ended September 30, 2018, as compared to 49% of our total revenue for the three months ended September 30, 2017.

Total equivalent production was 43.6 Mmcfe/d for the three months ended September 30, 2018, compared to 53.2 Mmcfe/d in the prior year quarter. The expected year over year decline in natural gas production from our offshore properties was only partially offset by the fact that the percentage of lower volumetric equivalent production from higher-value oil and NGLs increased from 32% to 39% due to our oil-weighted West Texas drilling program production. West Texas accounted for 15% of total equivalent production for the three months ended September 30, 2018, as compared to 6% of total equivalent production for the three months ended September 30, 2017.

Average Sales Prices

The average equivalent sales price realized for the three months ended September 30, 2018 was $4.86 per Mcfe compared to $3.84 per Mcfe for the three months ended September 30, 2017. This increase was attributable primarily to the increase in the realized price of oil to $61.92 per barrel, compared to $46.30 per barrel for the three months ended September 30, 2017, and to the increase in the realized price of natural gas liquids to $31.59 per barrel, compared to $22.98 per barrel for the three months ended September 30, 2017. The increase in the average equivalent price also was a result of the increase in oil and liquids as a percentage of total production.

Oil sales were 44% of our third quarter total sales. This compares to 32% of total sales for the prior year quarter. West Texas, which is our largest oil producing area, accounted for approximately 44% of total oil sales during the three months ended September 30, 2018, compared to approximately 35% of total oil sales during the prior year quarter. Our oil in West Texas is sold at prices indexed to Midland hub pricing, which has been and remains subject to a significant negative price differential compared to West Texas Intermediate Cushing hub pricing. This negative pricing differential increased from an average of $(0.75) per barrel for the three months ended September 30, 2017 to an average of $(12.66) per barrel for the three months ended September 30, 2018.

Operating Expenses

Operating expenses for the three months ended September 30, 2018 were approximately $6.4 million, or $1.59 per Mcfe, compared to $7.0 million, or $1.44 per Mcfe, for the three months ended September 30, 2017. The table below provides additional detail of operating expenses for the three month periods:

	Three Months Ended September 30,			
	2018		2017	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 4,393	$ 1.09	$ 4,585	$ 0.94
Production & ad valorem taxes	800	0.20	625	0.13
Transportation & processing costs	1,224	0.30	868	0.18
Workover costs	(35)	—	963	0.19
Total operating expenses	$ 6,382	1.59	$ 7,041	$ 1.44

Lease operating expenses were $4.4 million for the three months ended September 30, 2018, compared to $4.6 million for the three months ended September 30, 2017. The increase in the average expense per unit was due to lower overall production from other areas, primarily offshore, for the three months ended September 30, 2018.

Production and ad valorem taxes were $0.8 million for the three months ended September 30, 2018, compared to $0.6 million for the three months ended September 30, 2017, an increase primarily as a result of new and increased production in our West Texas area and a lower percentage of tax free offshore production.

Transportation and processing costs were $1.2 million for the three months ended September 30, 2018, compared to $0.9 million for the three months ended September 30, 2017, an increase primarily due to an additional accrual in the third quarter of 2018 for an anticipated throughput commitment fee deficiency through September 30, 2019, partially offset by a reduction in costs resulting from our offshore gas production now being routed through a single lower cost pipeline, as well as a new pipeline we constructed in early 2018 resulting in lower transportation expense on our condensate.

Impairment Expenses

Impairment expenses for the three months ended September 30, 2018 included a $72.2 million proved property non-cash impairment, which consisted of a $59.4 million impairment of carrying costs of our Gulf of Mexico properties due to revised proved reserve estimates, prepared by our third party engineers, made during the current quarter as a result of new bottom hole pressure data gathered during the planned installation of a second stage of compression in our Eugene Island 11 field and a $12.8 million impairment of certain of our non-core properties in Southeast Texas related to reducing such properties to their fair value as a result of a planned sale. See Note 3 – "Acquisitions and Dispositions" for further information regarding the planned sale of such non-core properties in Southeast Texas. 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. Impairment expenses for the three months ended September 30, 2018 also included $0.1 million non-cash impairment of unproved properties. No impairment expense was recorded for the three months ended September 30, 2017.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the three months ended September 30, 2018 was approximately $12.9 million, or $3.20 per Mcfe. This compares to approximately $11.2 million, or $2.28 per Mcfe, for the three months ended September 30, 2017. The higher depletion expense for the three months ended September 30, 2018 was attributable primarily to the higher depletion rate, calculated as a percentage of production to estimated reserves, as a result of the downward revision of offshore reserve estimates.

General and Administrative Expenses

Total general and administrative expenses for the three months ended September 30, 2018 were approximately $6.7 million, compared to $6.2 million for the three months ended September 30, 2017. The increase is general and administrative expenses for the three months ended September 30, 2018 primarily related to a $1.8 million severance accrual attributable to the resignation of our former President and CEO in September 2018, which was partially offset by $0.9 in million lower salaries and accrued bonuses during the current quarter and a $0.7 million decrease in non-cash stock based compensation attributable to forfeited restricted stock and PSUs, also related to the resignation of our former President and CEO. The non-cash stock-based compensation was approximately $0.8 million and $1.5 million for the three months ended September 30, 2018 and 2017, respectively. Exclusive of non-cash stock-based compensation and other non-recurring items in 2018, general and administrative expenses for the three months ended September 30, 2018 were approximately $3.8 million, compared to $4.7 million for the three months ended September 30, 2017

Gain (Loss) from Affiliates

For the three months ended September 30, 2018 and September 30, 2017, we recorded a loss from affiliates of approximately $0.3 million, net of no tax expense, and a gain of $0.5 million, net of no tax expense, respectively, related to our investment in Exaro.

Gain (Loss) from Sale of Assets

During the three months ended September 30, 2018 we recorded a gain on sale of assets of $0.5 million related to the sale of energy credits to a third party. During the three months ended September 30, 2017 we recorded a loss on sale of assets of $0.2 million related to the sale of non-core properties in our South Texas area.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

We reported revenues of $58.4 million for the nine months ended September 30, 2018, compared to revenues of $58.5 million for the nine months ended September 30, 2017. The decline in revenue attributable to lower gas production, primarily from natural decline in our offshore properties, was offset by the higher percentage of production from oil and the benefit of higher oil and NGL prices. Oil and NGL sales were 63% of our total revenue for the nine

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months ended September 30, 2018, as compared to 45% of our total revenue for the nine months ended September 30, 2017.

Total equivalent production was 45.3 Mmcfe/d for the nine months ended September 30, 2018, compared to 56.3 Mmcfe/d in the prior year. The expected year over year decline in equivalent production volumes was offset in part by the fact that the percentage of lower volumetric equivalent production from higher-value oil and NGLs increased from 31% to 38% due to our oil-weighted West Texas drilling program production. The nine months ended September 30, 2018 included a 1.4 Mmcfe/d decrease in production due to downtime related to an offshore compressor installation and maintenance. West Texas accounted for 13% of total equivalent production for the nine months ended September 30, 2018, as compared to 4% of total equivalent production for the nine months ended September 30, 2017.

Average Sales Prices

The average equivalent sales price realized for the nine months ended September 30, 2018 was $4.72 per Mcfe compared to $3.81 per Mcfe for the nine months ended September 30, 2017. This increase was attributable primarily to the increase in the realized price of oil to $62.76 per barrel, compared to $46.76 per barrel for the nine months ended September 30, 2017, and to the increase in the realized price of natural gas liquids to $27.45 per barrel, compared to $21.26 per barrel for the nine months ended September 30, 2017. The increase in the average equivalent price also was a result of the increase in oil and liquids as a percentage of total production.

Oil sales were 46% of our first nine month revenues. This compares to approximately 31% of total sales for the prior year period. West Texas, which is our largest oil producing area, accounted for approximately 41% of total oil sales during the nine months ended September 30, 2018 compared to approximately 23% of total oil sales during the prior year period. Our oil in West Texas is sold at prices indexed to Midland hub pricing, which has been and remains subject to a significant negative price differential compared to West Texas Intermediate Cushing hub pricing. This negative pricing differential increased from an average of $(0.30) per barrel for the nine months ended September 30, 2017 to an average of $(5.81) per barrel for the nine months ended September 30, 2018.

Operating Expenses

Operating expenses for the nine months ended September 30, 2018 were approximately $19.8 million, or $1.60 per Mcfe, compared to $20.2 million, or $1.32 per Mcfe, for the nine months ended September 30, 2017. The table below provides additional detail of operating expenses for the nine month periods:

	Nine Months Ended September 30,	
	2018	2017

	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 14,289	$ 1.15	$ 13,428	$ 0.87
Production & ad valorem taxes	2,418	0.20	1,993	0.13
Transportation & processing costs	2,106	0.17	2,982	0.19
Workover costs	974	0.08	1,800	0.13
Total operating expenses	$ 19,787	1.60	$ 20,203	$ 1.32

Lease operating expenses were $14.3 million for the nine months ended September 30, 2018, compared to $13.4 million for the nine months ended September 30, 2017, as we continued to add new wells and facilities to our new West Texas position. The increase in the average expense per unit was due to lower overall production from other areas, primarily offshore, for the nine months ended September 30, 2018.

Production and ad valorem taxes were $2.4 million for the nine months ended September 30, 2018, compared to $2.0 million for the nine months ended September 30, 2017, an increase primarily as a result of new and increased production in our West Texas area and a lower percentage of tax free offshore production.

Transportation and processing costs decreased by approximately $0.9 million for the nine months ended September 30, 2018, compared to the nine months ended September 30, 2017, primarily due to lower offshore production and a prior period adjustment related to an offshore processing fee overcharge. In addition, the decrease in transportation and processing costs during the nine months ended September 30, 2018 can be contributed to substantially

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all of our offshore gas production is now routed through a single lower cost pipeline, as well as a new pipeline we constructed in early 2018 resulting in lower transportation expense on our condensate.

Impairment Expenses

Impairment expenses for the nine months ended September 30, 2018 included a $74.9 million proved property non-cash impairment, which included a $61.7 million impairment related primarily to the impairment of carrying costs of our Gulf of Mexico properties due to revised proved reserve estimates, prepared by our third party engineers, made during the third quarter as a result of new bottom hole pressure data gathered during the planned installation of a second stage of compression in our Eugene Island 11 field. Also included in impairment expenses for the nine months ended September 30, 2018, was onshore proved property impairment of $13.2 million, of which $12.8 million was impairment of certain of our non-core properties in Southeast Texas related to reducing such properties to their fair value as a result of a planned sale. See Note 3 – "Acquisitions and Dispositions" for further information regarding the planned sale of such non-core properties in Southeast Texas. 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. Impairment expenses for the nine months ended September 30, 2018 also included approximately $1.3 million non-cash impairment of non-core onshore unproved properties primarily due to expiring leases. Impairment expenses for the nine months ended September 30, 2017 were $1.4 million related to the impairment of two unused offshore platforms which were subsequently sold.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the nine months ended September 30, 2018 was approximately $32.8 million, or $2.65 per Mcfe. This compares to approximately $35.7 million, or $2.32 per Mcfe, for the nine months ended September 30, 2017. Although depletion expense decreased during the current year, the higher depletion expense per unit was attributable primarily to the decrease in offshore production during the nine months ended September 30, 2018.

General and Administrative Expenses

Total general and administrative expenses for the nine months ended September 30, 2018 were approximately $18.8 million, compared to $18.6 million for the nine months ended September 30, 2017. The increase in general and administrative expenses for the nine months ended September 30, 2018 primarily related to a $1.8 million severance accrual attributable to the resignation of our former President and CEO in September 2018, which was partially offset by $1.6 million in lower salaries and accrued bonuses during the current year and a $0.8 million decrease in non-cash stock based compensation attributable to forfeited restricted stock and PSUs, also related to the resignation of our former President and CEO. The non-cash stock-based compensation was approximately $3.8 million and $4.6 million for the nine months ended September 30, 2018 and 2017, respectively. Exclusive of non-cash stock-based compensation and other non-recurring items in 2018, general and administrative expenses for the nine months ended September 30, 2018 were approximately $12.9 million, compared to $14.0 million for the nine months ended September 30, 2017.

Gain from Affiliates

For the nine months ended September 30, 2018 and September 30, 2017, we recorded a loss from affiliates of approximately $38,000, net of no tax expense, and a gain of $2.5 million, net of no tax expense, respectively, related to our investment in Exaro.

Gain from Sale of Assets

Gain from sale of assets for the nine months ended September 30, 2018 was approximately $11.3 million, including a $9.5 million gain from the sale of our operated Eagle Ford Shale assets in Karnes County, Texas, a $1.3 million gain from the sale of our non-operated assets in Starr County, Texas and a $0.5 million gain from the sale of energy credits to a third party. Gain from sale of assets for the nine months ended September 30, 2017 was approximately $2.3 million, which primarily included a $2.9 million gain related to the sale of all of our assets in the Bob West North area and our operated assets in the Escobas area, both located in Southeast Texas, partially offset by a $0.4 million loss on the sale of inventory.

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Capital Resources and Liquidity

During the three months ended September 30, 2018, we incurred expenditures of $15.9 million on capital projects, including $13.3 million for the drilling and completion of wells in the Southern Delaware Basin and $2.5 million in leasehold acquisition and other non-drilling costs in the Southern Delaware Basin. During the nine months ended September 30, 2018, we incurred expenditures of $44.8 million on capital projects, including $38.0 million for the drilling and completion of wells in the Southern Delaware Basin and $6.0 million in leasehold acquisition and other non-drilling costs in the Southern Delaware Basin. For the remainder of 2018, we have not budgeted to spend any significant amount of capital, as we intend to reduce our emphasis on drilling as the Midland-Cushing oil price differential in the region stabilizes and review liquidity-enhancing options to provide additional growth capital. We will use this time to both further evaluate well results and offset operator activity while infrastructure continues to develop in the area and to reduce outstanding debt, including through a reduction in general and administrative costs. Any further drilling during 2018 will be as necessary to maintain our Southern Delaware Basin acreage position.

Cash From Operating Activities

Cash flows from operating activities provided approximately $25.1 million in cash for the nine months ended September 30, 2018 compared to $26.1 million provided by operating activities for the same period in 2017. The table below provides additional detail of cash flows from operating activities for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30,	
	2018	2017
	(in thousands)	
Cash flows from operating activities, exclusive of changes in working capital accounts	$ 16,292	$ 20,733
Changes in operating assets and liabilities	8,851	5,372
Net cash provided by operating activities	$ 25,143	$ 26,105

Cash From Investing Activities

Net cash flows used in investing activities, comprised of capital expenditures net of proceeds from asset sales, were $21.2 million for the nine months ended September 30, 2018. We expended $43.2 million in cash capital costs, primarily related to drilling and/or completing wells in the Southern Delaware Basin, and acquiring or extending unproved leases, during the nine months ended September 30, 2018, partially offset by $22.1 million provided by the sale of our properties in Karnes County, Texas, the sale of non-operated properties in Starr County, Texas and the sale of energy credits to a third party. Cash flows used in investing activities for the nine months ended September 30, 2017 were $50.8 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.

Cash From Financing Activities

Cash flows used in financing activities for the nine months ended September 30, 2018 were approximately $4.0 million, primarily related to net repayment of borrowings outstanding under our credit facility. Cash flows provided by financing activities for the nine months ended September 30, 2017 were approximately $24.7 million, primarily related to net borrowings under our credit facility.

RBC Credit Facility

Our $500 million secured revolving credit facility with Royal Bank of Canada and other lenders (the “RBC Credit Facility”), currently expires October 1, 2019. The borrowing base under the facility is redetermined each November and May. As of September 30, 2018, the borrowing base under the RBC Credit Facility was $105 million. On November 2, 2018, we entered into the Sixth Amendment to the RBC Credit Facility (the “Sixth Amendment”), whereby the current borrowing base was reaffirmed at $105 million and will be reduced to $90 million on and after January 31, 2019, unless such reduction is waived by all lenders. Any excess of borrowings and letter of credit obligations outstanding after January 31, 2019 over such reduced borrowing base will be due and payable on or prior to March 1, 2019.

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The Sixth Amendment also provides for, among other things: (i) reducing the letter of credit issuance commitment capacity from $20.0 million to $5.0 million; (ii) waiving compliance with the required minimum 1.00 to 1.00 Current Ratio for the fiscal quarters ended September 30, 2018 and December 31, 2018; (iii) eliminating an exception from the restriction on payment of dividends, stock repurchases or redemptions of equity for repurchases under certain circumstances; (iv) waiving advance notice and a requirement for delivery of a revised reserve report related to the Liberty and Hardin County, Texas asset sale; and (v) requires delivery to the administrative agent of our internally-prepared monthly consolidated financial statements within 25 days of the end of such month. See Part II – Item 5. "Other Information" for additional discussion of the Sixth Amendment.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by us and require a Current Ratio of at least 1.00 to 1.00 and a Leverage Ratio of not more than 3.50 to 1.00, both as defined in the RBC Credit Facility Agreement. As of September 30, 2018, we were in compliance with all but the Current Ratio covenant under the RBC Credit Facility. We obtained a waiver for such non-compliance effective for September 30, 2018 and December 31, 2018 under the Sixth Amendment. 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 including the current ratio covenant, bankruptcy, insolvency or change of control events.

Pursuit of Refinancing and Other Liquidity-Enhancing Alternatives

Over the past few months, we have been in discussions with our current lenders and other sources of capital regarding a possible refinancing and/or replacement of our existing RBC Credit Facility, which matures on October 1, 2019. There is no assurance, however, that such discussions will result in a refinancing of the RBC Credit Facility on acceptable terms, if at all, or provide any specific amount of additional liquidity for future capital expenditures. These conditions raise substantial doubt about our ability to continue as a going concern. However, the accompanying financial statements have been prepared assuming we will continue to operate as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The accompanying financial statements do not include adjustments that might result from the outcome of the uncertainty, including any adjustments to reflect the possible future effects of the recoverability and classification of recorded asset amounts or amounts and classifications of liabilities that might be necessary should we be unable to continue as a going concern. Management has concluded that their plans alleviate the substantial doubt about our ability to continue as a going concern. The refinancing and/or replacement of the RBC Credit Facility could be made in conjunction with an issuance of unsecured or non-priority secured debt or preferred or common equity, non-core property monetization, potential monetization of certain midstream and/or water handling facilities, etc. or a combination of the foregoing. These discussions have included a possible new, replacement or extended credit facility that would be expected to provide additional borrowing capacity for future capital expenditures. While we review such liquidity-enhancing alternative sources of capital, we intend to continue to minimize our drilling program capital expenditures in the Southern Delaware Basin and pursue a reduction in our borrowings under the RBC Credit Facility, including through a reduction in cash general and administrative expenses and the possible sale of additional non-core properties.

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 2017 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."

Off Balance Sheet Arrangements

We may enter into off-balance sheet arrangements that can give rise to off-balance sheet obligations. As of September 30, 2018, the primary off-balance sheet arrangements that we have entered into are operating lease

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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 2017 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 three and nine months ended September 30, 2018, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate $2.0 million and $5.8 million impact on our revenues, respectively.

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, but we generally hedge 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 our current derivative contracts are large financial institutions and also lenders or affiliates of lenders in our 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 September 30, 2018, 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 Accounting Standards Codification Topic 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 Accounting Standards Codification 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.

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.

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As of September 30, 2018, our total long-term debt was $81.8 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 nine months ended September 30, 2018, our effective rates fluctuated between 4.9% and 8.25, depending on the term of the specific debt drawdowns. At September 30, 2018, we did not have any outstanding interest rate swap agreements. As of September 30, 2018, the weighted average interest rate on our variable rate debt was 5.97% 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 $0.6 million for the nine month period.

Other Financial Instruments

As of September 30, 2018, 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 September 30, 2018, an immediate 10% change in interest rates would result in a $0.5 million change on our near-term financial condition or results of operations.

Item 4. Controls and Procedures

Our management, with the participation of our Interim President and Chief Executive Officer and our Chief Financial and Accounting Officer, evaluated 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 September 30, 2018. Based upon that evaluation, our Interim President and Chief Executive Officer and our Chief Financial and Accounting Officer concluded that, as of September 30, 2018, 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 Interim President and Chief Executive Officer and our Chief Financial and 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 quarter ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

The adoption of Accounting Standard Codification Topic 606, Revenue from Contracts with Customers ("ASC 606") in January 2018, did require the implementation of new accounting processes during the quarter ended September 30, 2018, which changed the Company's internal controls relating to revenue by effecting a review on a quarterly basis of new contracts or modifications to existing contracts, as well as any significant increase in sales level primarily on gas processing or gas purchasing contracts to monitor the impact of ASC 606. See Note 2 to our Financial Statements – "Summary of Significant Accounting Policies – Adoption of ASC 606 – Impact of Adoption of ASC 606".

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of legal proceedings, see Note 11 to our Financial Statements – "Commitments and Contingencies."

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Item 1A. Risk Factors

The following additional risk factors should be read in conjunction with the risk factors disclosed in Item 1A of Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2017 and in Item 1A of Part II of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018:

We may not be able to refinance or replace our maturing funded debt on favorable terms, or at all, which will materially adversely affect our financial condition and our ability to develop our oil and gas assets.

Our RBC Credit Facility, which consists of substantially all of our funded debt matures on October 1, 2019, and under the Sixth Amendment to the RBC Credit Facility (the “Sixth Amendment”), the current borrowing base will be reduced on and after January 31, 2019 unless such reduction is waived by all lenders, as further discussed below. We have been involved in discussions with our current lenders and other sources of capital regarding alternatives that would include the replacement or refinancing of the RBC Credit Facility. There is no assurance, however, that such discussions will result in a refinancing of the RBC Credit Facility on acceptable terms, if at all or provide any specific amount of additional liquidity for future capital expenditures, and in such case there would be substantial doubt that the Company could continue as a going concern. Alternative sources of capital could involve the issuance of debt or equity on unfavorable terms or that would result in significant dilution. While we review such liquidity-enhancing alternative sources of capital, we intend to continue to minimize our drilling program capital expenditures in the Southern Delaware Basin and pursue a reduction in our borrowings under the RBC Credit Facility, including through a reduction in cash general and administrative expenses and the possible sale of additional non-core properties. We have faced challenges meeting certain financial performance covenants under our senior secured bank credit facility. The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by us and require a Current Ratio of at least 1.00 to 1.00 and a Leverage Ratio of not more than 3.50 to 1.00, both as defined in the RBC Credit Facility Agreement. As of September 30, 2018, we were not in compliance with the Current Ratio covenant under the RBC Credit Facility. We obtained a waiver for such non-compliance effective as of September 30, 2018 and for the quarter ending December 31, 2018 under the Sixth Amendment. In the future, we may be required to seek further waivers and modifications of covenants, or to further reduce our debt by, among other things, reducing our bank borrowing base, issuing equity or completing asset sales and other liquidity-enhancing activities, and these efforts may not be successful. In the absence of such a transaction, we may have to continue to be less aggressive in our drilling program, sell core and non-core assets, and further reduce general and administrative expenses in order to pay down outstanding debt under the RBC Credit Facility, or a combination of the foregoing. These transactions or actions could significantly impact the value of the Company and our ability to continue growth. We cannot assure you, however, that we will be able to successfully modify these covenants or obtain waiver for non-compliance or reduce our debt in the future. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the RBC Credit Facility or other agreements governing our indebtedness, an event of default could result, which could permit acceleration of such debt and acceleration of our other debt. Any accelerated debt would become immediately due and payable.

Our bank borrowing base is adjusted semiannually in May and November of each year, and upon requested unscheduled special redeterminations, in each case at the banks' discretion, and the amount is established and based, in part, upon certain external factors, such as commodity prices. Under the Sixth Amendment, effective November 2, 2018, the borrowing base of $105 million was reaffirmed but the borrowing base will be reduced to $90 million at January 31, 2019, unless such reduction is waived by all lenders. This lowering of our borrowing base will limit availability under our bank credit facility or require us to seek different forms of financing arrangements, and we may not be able to access other external financial resources sufficient to enable us to repay the debt outstanding upon its maturity. If the outstanding debt under our bank credit facility were to ever exceed the borrowing base, we would be required to repay the excess amount by March 31, 2019. Without any further extension of our RBC Credit Facility, it will be reflected as a current liability on our December 31, 2018 balance sheet, which may further limit our access to capital.

A sustained continuation of product transportation, processing and market constraints in the Southern Delaware Basin may adversely impact our results of operations and the value of our oil and gas properties in the region.

The Permian Basin, which includes the Southern Delaware Basin in which we have significant oil and gas properties, has been subject to significant product transportation and market constraints resulting from the increased drilling activity and consequent increased production of oil, natural gas and natural gas liquids in the region. One of the results of these constraints over the past year is the development of significant negative field pricing differentials for

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Southern Delaware Basin oil, natural gas and natural gas liquids production when compared to prices at major domestic oil and natural gas product hubs. For example, in recent months, pricing for oil of similar quality quoted for delivery within the Permian Basin at the Midland oil hub has been between $12 to $15 per barrel lower than West Texas Intermediate oil deliveries at the Cushing and Oklahoma oil hub. The 2019 calendar year strip for the Midland-Cushing differential on November 2, 2018 was $(5.55). While extensive capital investments are being made to provide additional production transportation, natural gas processing and alternative markets in the region, there is no assurance as to when or if any of these additional midstream and alternative market projects might be made available to our production or at what cost. If these constraints and consequent pricing differentials continue unabated for a significant amount of time, the financial returns for oil and gas assets in the Southern Delaware Basin may be considerably devalued when compared to oil and gas investments in hydrocarbon producing regions with greater access to major hydrocarbon markets.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The Company withheld the following shares from employees during the three months ended September 30, 2018 for the payment of taxes due on shares of restricted stock that vested and were issued under its stock-based compensation plans:

Period	Total Number of Shares Withheld	Average Price Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet be Purchased Under Program
July 2018	225	$ 6.00	—	$ —
August 2018	—	$ —	—	$ —
September 2018	27,635	$ 6.28	—	$ —
Total	27,860	$ 6.28	—	$ 31.8 million (1)

(1) In September 2011, the Company’s board of directors approved a $50 million share repurchase program. All shares are to be purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases are subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Pursuant to the Sixth Amendment of the RBC Credit Facility, the Company’s ability to acquire shares under this plan has been suspended.

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

On November 2 2018, the Company entered into the Sixth Amendment to the RBC Credit Facility which provides for the following:

· reaffirms the current borrowing base at $105.0 million, which borrowing base will be reduced to $90.0 million on and after January 31, 2019 unless waived by all lenders, and provides that the excess of any outstanding borrowings and letter of credit obligations outstanding after January 31, 2019 over such reduced borrowing base will be due and payable on or prior to March 1, 2019;

· reduces the letter of credit issuance commitment capacity under the RBC Credit Facility from $20.0 million to $5.0 million;

· waives compliance with the required minimum 1.00 to 1.00 current ratio of Current Assets to Current Liabilities (as such terms are defined in the RBC Credit Facility) for the last day of each of the fiscal quarters ended September 30, 2018 and December 31, 2018;

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- increases the percentage requirement to provide acceptable title information on oil and gas properties having not less than 90% of the discounted net present value of proved oil and gas reserves provided in the most recently delivered Company reserve report, as specified in the RBC Credit Facility;

- eliminates an exception from the restriction on payment of dividends, stock repurchases or redemptions of equity for repurchases under certain circumstances by the Company of its common stock under the Company's 2011 Company Stock Repurchase Plan;

- waives advance notice and a requirement for delivery of a revised reserve report related to the recently completed sale of certain non-core producing assets and related leaseholds located in Liberty County, Texas for approximately $6.0 million cash; and

- requires delivery to the administrative agent of internally-prepared monthly consolidated financial statements of the Company within 25 days of the end of such month, which failure to deliver such after a five day grace period shall constitute an event of default under the RBC Credit Facility.

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Item 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.1 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 and incorporated by reference herein).
3.2	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.4 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 and incorporated by reference herein).
3.3	Third Amended and Restated Bylaws of Contango Oil & Gas Company (filed as Exhibit 3.2 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 and incorporated by reference herein).
3.4	Certificate of Designations of Series A Junior Participating Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K dated August 1, 2018, as filed with the Securities and Exchange Commission on August 2, 2018 and incorporated by reference herein).
4.1	Rights Agreement, dated as of August 1, 2018, between Contango Oil & Gas Company, as the Company, and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated August 1, 2018, as filed with the Securities and Exchange Commission on August 2, 2018, and incorporated by reference herein).
10.1	Fifth Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders signatory thereto (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, as filed with the Securities and Exchange Commission on August 8, 2018 and incorporated by reference herein).
10.2	Separation Letter Agreement by Contango Oil & Gas Company and Allan D. Keel dated August 14, 2018 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 14, 2018, as filed with the Securities and Exchange Commission on August 15, 2018 and incorporated by reference herein).
10.3	Cooperation Agreement by Contango Oil & Gas Company and Allan D. Keel dated August 14, 2018 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated August 14, 2018, as filed with the Securities and Exchange Commission on August 15, 2018 and incorporated by reference herein).
10.4	Separation Agreement and Release of Claims by Contango Oil & Gas Company and Allan D. Keel dated October 9, 2018 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated October 9, 2018, as filed with the Securities and Exchange Commission on October 12, 2018 and incorporated by reference herein).
10.5	Sixth Amendment to Credit Agreement dated as of November 2, 2018 among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders signatory thereto. †
31.1	Certification of Chief Executive Officer required by Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934. †
31.2	Certification of Chief Financial Officer required by Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934. †
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *
101	Interactive Data Files †

†Filed herewith.

* Furnished herewith.

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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: November 7, 2018	By:	/s/ WILKIE S. COLYER Wilkie S. Colyer Interim President and Chief Executive Officer (Principal Executive Officer)
Date: November 7, 2018	By:	/s/ E. JOSEPH GRADY E. Joseph Grady Senior Vice President and Chief Financial and Accounting Officer (Principal Financial and Accounting Officer)