ABRAXAS PETROLEUM CORP
Form 10-Q
November 09, 2018

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED September 30, 2018

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: 001-16071

ABRAXAS PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Nevada	**74-2584033**
(State of Incorporation)	(I.R.S. Employer Identification No.)

18803 Meisner Drive, San Antonio, TX 78258

(Address of principal executive offices) (Zip Code)

210-490-4788
(Registrant's telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

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 the filing requirements for the past 90 days. Yes No

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

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

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
(Do not mark if a 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 Sec 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 number of shares of the issuer's common stock outstanding as of November 5, 2018 was 166,605,245.

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Forward-Looking Information

We make forward-looking statements throughout this report. Whenever you read a statement that is not simply a statement of historical fact (such as statements including words like “believe,” “expect,” “anticipate,” “intend,” “will,” “plan,” “may,” “estimate,” “could,” “potentially” or similar expressions), you must remember that these are forward-looking statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this report is generally located in the material set forth under the headings “Management’s Discussion and Analysis of Financial Condition and Results of Operations” but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- the prices we receive for our production and the effectiveness of our hedging activities;
- the availability of capital including under our credit facility;
- our success in development, exploitation and exploration activities;
- declines in our production of oil and gas;
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by our bank credit facility and restrictive debt covenants;
- our ability to make planned capital expenditures;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our ability to procure services and equipment for our drilling and completion activities;

- our acquisition and divestiture activities;
- weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- other factors discussed elsewhere in this report.

Initial production, or IP, rates, for both our wells and for those wells that are located near our properties, are limited data points in each well’s productive history. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rates are not necessarily indicative or predictive of future production rates, expected ultimate recovery, or EUR, or economic rates of return from such wells and should not be relied upon for such purpose. In addition, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease-line offsets. Abraxas' standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid-length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,500 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.

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GLOSSARY OF TERMS

Unless otherwise indicated in this report, gas volumes are stated at the legal pressure base of the State or area in which the reserves are located at 60 degrees Fahrenheit. Oil and gas equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of oil and gas:

"***Bbl***" – barrel or barrels.

"***Bcf***" – billion cubic feet of gas.

"***Bcfe***" – billion cubic feet of gas equivalent.

"***Boe***" – barrels of oil equivalent.

"***Boed or Boepd"*** – barrels of oil equivalent per day.

"***MBbl***" – thousand barrels.

*"**MBoe"*** **–** thousand barrels of oil equivalent.

"***Mcf***" – thousand cubic feet of gas.

"***Mcfe***" – thousand cubic feet of gas equivalent.

"***MMBbl***" – million barrels.

"***MMBoe***" – million barrels of oil equivalent.

"***MMBtu***" – million British Thermal Units of gas.

"***MMcf***" – million cubic feet of gas.

"***MMcfe***" – million cubic feet of gas equivalent.

"NGL" – natural gas liquids measured in barrels.

Terms used to describe our interests in wells and acreage:

"***Developed acreage***" means acreage which consists of leased acres spaced or assignable to productive wells.

"***Development well***" is a well drilled within the proved area of an oil or gas reservoir to the depth or stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting reserves.

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"***Dry hole***" is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion.

"***Exploratory well***" is a well drilled to find and produce oil and or gas in an unproved area, to find a new reservoir in a field previously found to be producing in another reservoir, or to extend a known reservoir.

"***Gross acres***" are the number of acres in which we own a working interest.

"***Gross well***" is a well in which we own a working interest.

"***Net acres***" are the sum of fractional ownership working interests in gross acres (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

"***Net well***" is the sum of fractional ownership working interests in gross wells.

"***Productive well***" is an exploratory or a development well that is not a dry hole.

"***Undeveloped acreage***" means those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

Terms used to assign a present value to or to classify our reserves:

"***Developed oil and gas reserves****" Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"Proved developed non-producing reserves*" are those quantities of oil and gas reserves that are developed behind pipe in an existing well bore, from a shut-in well bore or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

"Proved developed reserves"* Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"***Proved reserves****" Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves" *or* ***"PUDs*"*** Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.

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“***PV-10***” means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission (“SEC”). PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

“***Standardized Measure***” means estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation or de-escalation, calculated in accordance with Accounting Standards Codification (“ASC”) 932, “Disclosures About Oil and Gas Producing Activities.”

“Undeveloped oil and gas reserves*" Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

*This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition, see: http://www.ecfr.gov/cgi-bin/retrieveECFR?

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ABRAXAS PETROLEUM CORPORATION

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Part I

FINANCIAL STATEMENTS

Item 1. Financial Statements

ABRAXAS PETROLEUM CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(in thousands)

	September 30, 2018 (Unaudited)	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ -	$ 1,618
Accounts receivable:		
Joint owners, net	15,948	14,218
Oil and gas production sales	30,217	17,789
Other	254	86
	46,419	32,093
Derivative asset	470	-
Other current assets	739	778
Total current assets	47,628	34,489
Property and equipment		
Oil and gas properties, full cost method of accounting:		
Proved	1,047,913	923,237
Other property and equipment	39,277	39,136
Total	1,087,190	962,373
Less accumulated depreciation, depletion, amortization and impairment	(754,862)	(724,606)

Total property and equipment - net	332,328	237,767
Derivative asset	11	-
Deferred financing fees - net	1,261	1,285
Other assets	265	265
Total assets	$ 381,493	$ 273,806

See accompanying notes to condensed consolidated financial statements (unaudited).

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ABRAXAS PETROLEUM CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (CONTINUED)

(in thousands, except share and per share data)

	September 30, 2018 (Unaudited)	**December 31, 2017**
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 41,607	$ 45,570
Joint interest oil and gas production payable	30,692	11,502
Accrued interest	251	140
Other accrued liabilities	1,403	539
Derivative liabilities	22,845	10,837
Current maturities of long-term debt	264	262
Total current liabilities	97,062	68,850
Long-term debt - less current maturities	149,159	87,354
Other liabilities	132	132
Derivative liabilities long-term	17,188	2,387
Future site restoration	7,734	8,775
Total liabilities	271,275	167,498
Commitments and contingencies (Note 9)		
Stockholders' Equity		
Preferred stock, par value $0.01 per share - authorized 1,000,000 shares; - 0- shares issued and outstanding	-	-
Common stock, par value $0.01 per share, authorized 400,000,000 shares; 166,609,818 and 165,889,901 issued and outstanding at September 30, 2018 and December 31, 2017, respectively	1,666	1,659
Additional paid-in capital	417,372	415,471
Accumulated deficit	(308,820)	(310,822)
Total stockholders' equity	110,218	106,308
Total liabilities and stockholders' equity	$ 381,493	$ 273,806

See accompanying notes to condensed consolidated financial statements (unaudited).

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ABRAXAS PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(in thousands except per share data)

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2018	**2017**	**2018**	**2017**
Revenues:				
Oil	$37,039	$21,339	$100,505	$48,153
Gas	1,897	1,873	5,882	4,918
Natural gas liquids	2,677	1,495	6,735	3,559
	41,613	24,707	113,122	56,630
Other	12	15	49	46
	41,625	24,722	113,171	56,676
Operating costs and expenses				
Lease operating	6,724	4,089	17,023	11,628
Production and ad valorem taxes	3,569	2,045	9,167	4,823
Depreciation, depletion and amortization	11,011	7,877	29,846	17,666
General and administrative (including stock-based compensation of $428, $750, $1,894 and $2,499 respectively)	2,586	5,057	8,379	10,692
	23,890	19,068	64,415	44,809
Operating income	17,735	5,654	48,756	11,867
Other (income) expense:				
Interest income	-	-	(1)	(1)
Interest expense	2,083	868	5,039	1,876
Amortization of deferred financing fees	113	100	320	354
Loss (gain) on derivative contracts	13,568	5,456	41,215	(10,375)
Loss (gain) on sale of non-oil and gas assets	194	-	181	(102)
	15,958	6,424	46,754	(8,248)
Income (loss) before income tax	1,777	(770)	2,002	20,115
Income tax (expense) benefit	-	-	-	-
Net income (loss)	$1,777	$(770)	$2,002	$20,115
Net income (loss) per common share - basic	$0.01	$-	$0.01	$0.13
Net income (loss) per common share - diluted	$0.01	$-	$0.01	$0.12
Weighted average shares outstanding				

Basic	165,392	163,508	165,083	160,031
Diluted	167,629	163,508	167,865	161,597

See accompanying notes to condensed consolidated financial statements (unaudited).

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ABRAXAS PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2018	**2017**
Operating Activities:		
Net income	$2,002	$20,115
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss (gain) on sale of non-oil and gas assets	181	(102)
Net loss (gain) on derivative contracts	41,215	(10,375)
Derivative contract settlements	(16,575)	3,416
Depreciation, depletion and amortization	29,846	17,666
Amortization of deferred financing fees	320	354
Accretion of future site restoration	395	338
Stock-based compensation	1,894	2,499
Changes in operating assets and liabilities:		
Accounts receivable	(14,326)	(2,957)
Other assets	1,727	(812)
Accounts payable and accrued expenses	20,025	(7,883)
Net cash provided by operating activities	66,704	22,259
Investing Activities		
Capital expenditures, including purchase and development of properties	(132,989)	(71,518)
Proceeds from the sale of oil and gas properties	3,116	15,098
Proceeds from the sale of non-oil and gas assets	26	204
Net cash used in investing activities	(129,847)	(56,216)
Financing Activities		
Proceeds from long-term borrowings	93,000	60,000
Payments of long-term borrowings	(31,193)	(89,722)
Exercise of stock options	14	-
Proceeds from issuance of common stock	-	65,224
Deferred financing fees	(296)	(726)
Net cash provided by financing activities	61,525	34,776
(Decrease) increase in cash and cash equivalents	(1,618)	819
Cash and cash equivalents at beginning of period	1,618	-
Cash and cash equivalents at end of period	$-	$819

Supplemental disclosure of cash flow information:		
Interest paid	$4,402	$1,427
Non-cash investing and financing activities		
Issuance of stock for acquisition of oil and gas properties	$-	$3,335
Change in capital expenditures included in accounts payable	(3,823)	16,510
Decrease in asset retirement obligation in capital expenditures	(1,436)	-
	$(5,259)	$19,845

See accompanying notes to condensed consolidated financial statements (unaudited).

ABRAXAS PETROLEUM CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

(tabular amounts in thousands, except per share data)

1. Basis of Presentation

The accounting policies followed by Abraxas Petroleum Corporation and its subsidiaries (the “Company”) are set forth in the notes to the Company’s audited consolidated financial statements in the Annual Report on Form 10-K for the year ended December 31, 2017 filed with the SEC on March 16, 2018. Such policies have been continued without change. Also, refer to the notes to those financial statements for additional details of the Company’s financial condition, results of operations, and cash flows. All material items included in those notes have not changed except as a result of normal transactions in the interim, or as disclosed within this report. The accompanying interim condensed consolidated financial statements have not been audited by our independent registered public accountants, and in the opinion of management, reflect all adjustments necessary for a fair presentation of the financial position and results of operations. Any and all adjustments are of a normal and recurring nature. Although management believes the unaudited interim related disclosures in these condensed consolidated financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the SEC. The results of operations and the cash flows for the three and nine month periods ended September 30, 2018 are not necessarily indicative of the results to be expected for the full year. The condensed consolidated financial statements included herein should be read in conjunction with the consolidated audited financial statements and the notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2017.

Consolidation Principles

The terms “Abraxas,” “Abraxas Petroleum,” “we,” “us,” “our” or the “Company” refer to Abraxas Petroleum Corporation and of its subsidiaries, including Raven Drilling, LLC (“Raven Drilling”).

Rig Accounting

In accordance with SEC Regulation S-X, no income is to be recognized in connection with contractual drilling services performed in connection with properties in which the Company or its affiliates hold an ownership, or other economic interest. Any income not recognized as a result of this limitation is to be credited to the full cost pool and recognized through lower amortization as reserves are produced.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Recently Adopted Accounting Standards and Disclosures

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update, ("ASU") No. 2014-09, *Revenue from Contracts with Customers*. The Company completed a detailed analysis of its revenue streams at the individual contract level to evaluate the impact of the new revenue standard on its consolidated financial statements. Based on these completed assessments, adoption of this standard did not impact our net earnings. The Company adopted this new standard on January 1, 2018, using the modified retrospective method. No cumulative adjustment to retained earnings resulted from the adoption of this standard. See Note 2. "Impact of ASC 606 Adoption" and Note 3. "Revenue from Contracts with Customers" for further details related to the Company's adoption of this standard.

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Recent Accounting Standards and Disclosures Not Yet Adopted

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842*) (ASU 2016-02), which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for certain lease transactions. Additional disclosures about an entity's lease transactions will also be required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration." In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842*) - Land Easement Practical Expedient for Transition to Topic 842" (ASU 2018-01), which permits an entity an optional election to not evaluate under ASU 2016-02 those existing or expired land easements that were not previously accounted for as leases prior to the adoption of ASU 2016-02. Additionally, in July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842*) - Targeted Improvements" (ASU 2018-11), which permits an entity (i) to apply the provisions of ASU 2016-02 at the adoption date instead of the earliest period presented in the financial statements, and, as a lessor, (ii) to account for lease and nonlease components as a single component as the nonlease components would otherwise be accounted for under the provisions of ASU 2014-09. ASU 2016-02 and other related ASUs are effective for interim and annual periods beginning after December 31, 2018, and early application is permitted. Based on the provisions of ASU 2018-11 and other related ASUs, lessees and lessors may recognize and measure leases at the beginning of the earliest period presented in the financial statements, defined as the effective date, using a modified retrospective approach, or at the adoption date by recognizing a cumulative-effect adjustment to the opening balance of retained earnings.

The Company is continuing its assessment of ASU 2016-02 by implementing its project plan, evaluating certain operational and corporate policies and processes, further defining its population of leases and reviewing numerous contracts. As part of our assessment work to date, we have engaged external resources to assist us in our efforts of completing the analysis of potential changes to our current accounting practices. Additionally, we have not determined the effect of the ASU on our internal control over financial reporting or other changes in business practices and processes. The Company plans to elect the package of practical expedients within ASU 2016-02 that allows an entity to not reassess prior to the effective date (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases, or (iii) initial direct costs for any existing leases. Additionally, The Company plans to elect the practical expedient under ASU 2018-01 and not evaluate existing or expired land easements not previously accounted for as leases prior to the effective date. We do not expect the adoption of this standard will have a material impact on our financial statements. The Company does not intend to early-adopt ASU 2016-02 and other related ASUs and will adopt this new standards update in first quarter 2019 using a modified retrospective approach and will recognize a right of use asset and lease liability on the adoption date. We also anticipate to elect a policy not to recognize right of use assets and lease liabilities related to short-term leases.

Stock-Based Compensation and Option Plans

Stock Options

The Company currently utilizes a standard option-pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors.

The following table summarizes the Company’s stock-based compensation expense related to stock options for the periods presented:

Three Months Ended September 30,		**Nine Months Ended September 30,**	
2018	**2017**	**2018**	**2017**
$327	$376	$1,241	$1,445

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The following table summarizes the Company's stock option activity for the nine months ended September 30, 2018 (shares in thousands):

	Number of Shares	**Weighted Average Option Exercise Price Per Share**	**Weighted Average Grant Date Fair Value Per Share**
Outstanding , December 31, 2017	8,317	$ 2.35	$ 1.67
Granted	300	$ 2.80	$ 1.87
Exercised	(374)	$ 1.72	$ 1.19
Forfeited	(579)	$ 2.62	$ 1.87
Outstanding , September 30, 2018	7,664	$ 2.38	$ 1.68

As of September 30, 2018, there was approximately $0.7 million of unamortized compensation expense related to outstanding stock options that will be recognized from 2018 through 2021.

Restricted Stock Awards

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the recipient of the award terminates employment with the Company prior to the lapse of the restrictions. The fair value of such shares of restricted stock was determined using the closing price on the grant date and compensation expense is recorded over the applicable vesting periods.

The following table summarizes the Company's restricted stock activity for the nine months ended September 30, 2018 (shares in thousands):

Number	**Weighted Average**

	of Shares	Grant Date Fair Value Per Share
Unvested, December 31, 2017	1,479	$ 3.43
Granted	753	$ 2.22
Vested/ Released	(743)	$ 3.13
Forfeited	(180)	$ 3.28
Unvested September 30, 2018	1,309	$ 2.92

The following table summarizes the Company's stock-based compensation expense related to restricted stock for the periods presented:

Three Months Ended September 30,		**Nine Months Ended September 30,**	
2018	**2017**	**2018**	**2017**
$26	$374	$494	$896

As of September 30, 2018, there was approximately $1.3 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized from 2018 through 2021.

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Performance Based Restricted Stock Awards

Effective on April 1, 2018, the Company issued performance-based shares of restricted stock to certain officers and employees under the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. The shares will vest in 2021 upon the achievement of performance goals based on the Company's Total Shareholder Return ("TSR") as compared to a peer group of companies. The number of shares which would vest depends upon the rank of the Company's TSR as compared to the peer group at the end of the three-year vesting period, and can range from zero percent of the initial grant up to 200% of the initial grant.

The table below provides a summary of Performance Based Restricted Stock as of the date indicated (shares in thousands):

	Number of Shares	**Weighted Average Option Exercise Price Per Share**
Unvested, December 31, 2017	-	$ -
Granted	464	$ 2.37
Vested/ Released	-	$ -
Forfeited	(59)	$ 2.37
Unvested September 30, 2018	405	$ 2.37

Compensation expense associated with the performance based restricted stock is based on the grant date fair value of a single share as determined using a Monte Carlo Simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the performance based restricted stock awards with shares of the Company's common stock, the awards are accounted for as equity awards and the expense is calculated on the grant date assuming a 100% target payout and amortized over the life of the awards.

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The following table summarizes the Company's stock-based compensation expense related to performance based restricted stock for the periods presented:

Three Months Ended September 30,		Nine Months Ended September 30,	
2018	**2017**	**2018**	**2017**
$ 75	$ -	$ 159	$ -

As of September 30, 2018, there was approximately $0.8 million of unamortized compensation expense relating to outstanding performance based restricted shares that will be recognized from 2018 through 2021.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all direct costs and certain indirect costs associated with the acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated net revenue from proved reserves discounted at 10% are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties for full cost accounting companies with proceeds accounted for as an adjustment of capitalized cost. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. The Company applies the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. At September 30, 2018 and 2017, our net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves.

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Restoration, Removal and Environmental Liabilities

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a non-capital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component is fixed or reliably determinable.

The Company accounts for future site restoration obligations based on the guidance of ASC 410 which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. ASC 410 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense in the accompanying condensed consolidated financial statements.

The following table summarizes the Company’s future site restoration obligation transactions for the nine months ended September 30, 2018 and the year ended December 31, 2017:

	September 30, 2018	**December 31, 2017**
Beginning future site restoration obligation	$ 8,775	$ 8,623
New wells placed on production and other	536	1,088
Deletions related to property disposals and plugging costs	(1,809)	(1,551)
Accretion expense and other	395	451
Revisions and other	(163)	164
Ending future site restoration obligation	$ 7,734	$ 8,775

2. Impact of ASC 606 Adoption

On January 1, 2018, the Company adopted ASU No. 2014-09, “*Revenue from Contracts with Customers*” (“ASU 2014-09”) using the modified retrospective method of transition. Under this method of transition, the Company applied ASU 2014-09 to all new contracts entered into on and after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue attributable to a contract had not been recognized under legacy revenue guidance.

ASU 2014-09 supersedes nearly all existing revenue recognition guidance under U.S. GAAP and includes a five step process to recognize revenue when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services.

For the nine months ended September 30, 2018, there was no impact to the Company's reported revenues, operating costs and expenses or net income as a result of adopting ASU 2014-09, as compared to legacy revenue guidance. In addition, no cumulative catch-up adjustment to accumulated deficit was required on January 1, 2018 as a result of adopting ASU 2014-09.

3. Revenue from Contracts with Customers

Revenue Recognition

Sales of oil, gas and NGL are recognized at the point in time when control of the product is transferred to the customer and collectability is reasonably assured. The Company's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, physical location, quality of the oil or gas, and prevailing supply and demand conditions. As a result, the price of the oil, gas and NGL fluctuates to remain competitive with other available oil, gas and NGL supplies in the market. The Company believes that the pricing provisions of our oil, gas and NGL contracts are customary in the industry.

Oil sales

The Company's oil sales contracts are generally structured such that it sells its oil production to a purchaser at a contractually specified delivery point at or near the wellhead. The crude oil production is priced on the delivery date based upon prevailing index prices less certain deductions related to oil quality, physical location and transportation costs incurred by the purchaser subsequent to delivery. The Company recognizes revenue when control transfers to the purchaser upon delivery at or near the wellhead at the net price received from the purchaser.

Gas and NGL Sales

Under the Company's gas processing contracts, it delivers wet gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity processes the gas and remits proceeds to the Company based upon either (i) the resulting sales price of NGL and residue gas received by the midstream processing entity from third party customers or (ii) the prevailing index prices for NGL and residue gas in the month of delivery to the midstream processing entity. Gathering, processing, transportation and other expenses incurred by the midstream processing entity are typically deducted from the proceeds that the Company receives.

In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. With respect to the Company's gas purchase contracts, the Company has concluded that it is the agent, and thus, the midstream processing entity is its customer. Accordingly, the Company recognizes revenue upon delivery to the midstream processing entity based on the net amount of the proceeds received from the midstream processing entity.

Imbalances

The Company utilizes the sales method to account for gas production imbalances. Under this method, income is recorded based on the Company's net revenue interest in production taken for delivery. The Company had no material gas imbalances at September 30, 2018 and 2017.

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Disaggregation of Revenue

The Company is focused on the development of oil and natural gas properties primarily located in the following three operating regions in the United States: (i) the Permian/Delaware Basin, (ii) Rocky Mountain and (iii) South Texas. Revenue attributable to each of those regions is disaggregated in the tables below.

	Three Months Ended September 30,					
	2018			2017		
	Oil	Gas	NGL	Oil	Gas	NGL
Operating Region						
Permian/Delaware Basin	$11,433	$681	$890	$5,683	$825	$448
Rocky Mountain	$23,743	$939	$1,741	$14,564	$649	$1,021
South Texas	$1,863	$277	$46	$1,092	$399	$26

	Nine Months Ended September 30,					
	2018			2017		
	Oil	Gas	NGL	Oil	Gas	NGL
Operating Region						
Permian/Delaware Basin	$35,471	$2,209	$2,301	$9,832	$2,152	$1,149
Rocky Mountain	$58,462	$2,740	$4,324	$34,205	$1,949	$2,338
South Texas	$6,572	$933	$110	$4,116	$817	$72

Significant Judgments

Principal versus agent

The Company engages in various types of transactions in which midstream entities process the Company's gas and subsequently market resulting NGL and residue gas to third-party customers on behalf of the Company, such as the Company's percentage-of-proceeds and gas purchase contracts. These types of transactions require judgment to determine whether we are the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net.

Transaction price allocated to remaining performance obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC Topic 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606-10-50-14(a) which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under the Company's product sales contracts, the Company is entitled to payment from purchasers once its performance obligations have been satisfied upon delivery of the product, at which point payment is unconditional. The Company records invoiced amounts as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheet.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and also recorded as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheets. In this scenario, payment is also unconditional, as the Company has satisfied its performance obligations through delivery of the relevant product. As a result, the Company has concluded that its product sales do not give rise to contract assets or liabilities under ASU 2014-09. At September 30, 2018 and December 31, 2017, our receivables from contracts with customers were $30.2 million and $17.8 million, respectively.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain gas and NGL sales may not be received for 30 to 60 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the midstream purchaser and the price that will be received for the sale of the product. Additionally, to the extent actual volumes and prices of oil are unavailable for a given reporting period because of timing or information not received from third party purchasers, the expected sales volumes and prices for those barrels of oil are also estimated.

The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the three and nine months ended September 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

4. Income Taxes

The Company records income taxes using the liability method. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities and are measured using the tax rates and laws expected to be in effect when the differences are expected to reverse.

For the three and nine months ended September 30, 2018 and 2017, there was no income tax expense due to net operating loss carryforwards ("NOLs") and the Company recorded a full valuation allowance against its net deferred taxes.

At December 31, 2017, the Company had, subject to the limitation discussed below, $245.2 million of NOLs for U.S. tax purposes. The Company's pre-2018 NOL's will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising after January 1, 2018 can generally be carried forward indefinitely and can offset up to 80% of future taxable income for regular tax purposes. Since January 1, 2018, the alternative minimum tax is no longer applicable to corporations.

The use of the Company's NOLs will be limited if there is an "ownership change" in its common stock, generally a cumulative ownership change exceeding 50% during a three year period, as determined under Section 382 of the

Internal Revenue Code. As of September 30, 2018, the Company has not had an ownership change as defined by Section 382. Given historical losses, uncertainties exist as to the future utilization of the NOL carryforwards. Therefore, the Company has established a valuation allowance of $80.4 million for deferred tax assets at December 31, 2017.

As of September 30, 2018, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2013 through 2017 remain open to examination by the tax jurisdictions to which the Company is subject.

New tax legislation, commonly referred to as the Tax Cuts and Jobs Act (H.R. 1), was enacted on December 22, 2017. ASC 740, *Accounting for Income Taxes*, requires companies to recognize the effect of tax law changes in the period of enactment even though the effective date for most provisions is for tax years beginning after December 31, 2017. Since our federal deferred tax asset was fully offset by a valuation allowance, the reduction in the U.S. corporate income tax rate to 21% did not materially affect the Company's financial statements. Significant provisions that are not yet effective but may impact income taxes in future years include: the repeal of the corporate alternative minimum tax, the limitation on the current deductibility of net interest expense in excess of 30% of adjusted taxable income for levered balance sheets, a limitation on utilization of NOLs generated after tax year 2017 to 80% of taxable income, the unlimited carryforward of NOLs generated after tax year 2017, temporary 100% expensing of certain business assets, additional limitations on certain general and administrative expenses, and changes in determining the excessive compensation limitation. Currently, the Company does not anticipate paying cash federal income taxes in the near term due to any of the legislative changes, primarily due to the availability of our NOL carryforwards. Future interpretations relating to the recently enacted U.S. federal income tax legislation which vary from our current interpretation and possible changes to state tax laws in response to the recently enacted federal legislation may have a significant effect on this projection.

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5. Long-Term Debt

The following is a description of the Company’s debt as of September 30, 2018 and December 31, 2017, respectively:

	September 30, 2018	December 31, 2017
	(In thousands)	
Senior secured credit facility	$ 146,000	$ 84,000
Real estate lien note	3,423	3,616
	149,423	87,616
Less current maturities	(264)	(262)
	$ 149,159	$ 87,354

Credit Facility

The Company has a senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. As of September 30, 2018, $146.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. At September 30, 2018, the Company had a borrowing base of $200.0 million. The borrowing base is determined semi-annually by the lenders based upon the Company's reserve reports, one of which must be prepared by its independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of the Company's proved reserves securing the facility utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and the Company is able to request one redetermination during any six-month period between scheduled redeterminations. Outstanding borrowings in excess of the borrowing base must be repaid immediately or the Company must pledge additional oil and gas properties or other assets as collateral. The Company does not currently have any substantial unpledged assets and it may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause the Company to fail to be in compliance with the financial covenants described below. The Company's borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of its then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. The Company's borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest (a) at any time an event of default exists, at 3% per annum plus the amounts set forth below, and (b) at all other times, at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the Federal Funds Rate plus 0.5%, and (z) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (i)

1.5%-2.5%, depending on the utilization of the borrowing base, or (ii) if we elect, LIBOR plus, in each case, 2.5%-3.5% depending on the utilization of the borrowing base. At September 30, 2018, the interest rate on the credit facility was approximately 5.2% assuming LIBOR borrowings.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is May 16, 2021. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company is permitted to terminate the credit facility and is able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of the Company's subsidiaries has guaranteed our obligations under the credit facility on a senior secured basis. Obligations under the credit facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the Company and its subsidiary guarantors' material property and assets. The collateral is required to include properties comprising at least 90% of the PV-10 of the Company's proven reserves. The Company has also granted its lenders a security interest in our headquarters building.

Under the credit facility, the Company is subject to customary covenants, including certain financial covenants and reporting requirements. The Company is required to maintain a current ratio, as defined in the credit facility, as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio of not less than 2.50 to 1.00. The Company is also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio of not more than 3.50 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, EBITDAX is defined as the sum of consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts plus expenses incurred in connection with the negotiation, execution, delivery and performance of the credit facility plus expenses incurred in connection with any acquisition permitted under the credit facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to $1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses minus all non-cash items of income which were included in determining consolidated net loss, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the headquarters building and obligations with respect to surety bonds and derivative contracts.

At September 30, 2018, the Company was in compliance with all of these financial covenants. As of September 30, 2018, as defined by the credit agreement, the interest coverage ratio was 14.6 to 1.00, the total debt to EBITDAX ratio was 1.79 to 1.00, and our current ratio was 1.37 to 1.00.

The credit facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an “arm’s length” basis;

- make any change in the principal nature of our business; and

- permit a change of control.

The credit facility also contains certain additional covenants including requirements that:

- 100% of the net proceeds from any terminations of derivative contracts must be used to repay amounts outstanding under the credit facility; and

- if the sum of our cash on hand plus liquid investments exceeds $10.0 million, then the amount in excess of $10.0 million must be used to pay amounts outstanding under the credit facility.

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities. As of September 30, 2018, the Company was in compliance with all of the terms of the credit facility.

Real Estate Lien Note

The Company has a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note was modified on June 20, 2018 to a fixed rate of 4.9% and is payable in monthly installments of $35,672. The maturity date of the note is July 20, 2023. As of September 30, 2018, and December 31, 2017, $3.4 million and $3.6 million, respectively was outstanding on the note.

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6. Earnings per Share

The following table sets forth the computation of basic and diluted earnings per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
	(in thousands, except per share data)			
Numerator:				
Net income (loss)	$1,777	$(770)	$2,002	$20,115
Denominator for basic earnings per share - weighted-average common shares outstanding	165,392	163,508	165,083	160,031
Effect of dilutive securities: Stock options, restricted shares and performance based shares	2,237	-	2,782	1,566
Denominator for diluted earnings per share - adjusted weighted-average shares and assumed exercise of options, restricted shares and performance based shares	167,629	163,508	167,865	161,597
Net income per common share - basic	$0.01	$-	$0.01	$0.13
Net income per common share - diluted	$0.01	$-	$0.01	$0.12

Basic net income per share, excluding any dilutive effects of stock options, unvested restricted stock and unvested performance based shares, is computed by dividing net income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted net income per share is computed in a manner similar to basic; however diluted net income per share reflects the assumed conversion of all potentially dilutive securities. For the three months ended September 30, 2017, 1.3 million shares relating to stock options and unvested restricted shares were excluded from the calculation of diluted loss per share since their inclusion would have been anti-dilutive due to the loss incurred in the period. For the three and nine months ended September 30, 2018 and the nine month period ended September 30, 2017, no shares related to options, or unvested restricted shares were omitted from the calculation of diluted income per share.

7. Hedging Program and Derivatives

The derivative contracts the Company utilizes are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. The Company's derivative contracts do not qualify for hedge accounting; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. There are no netting agreements relating to these derivative contracts and there is no policy to offset.

The following table sets forth the summary position of our derivative contracts as of September 30, 2018:

	Oil - WTI	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
Fixed Swaps		
October - December 2018	4,477	$53.70
January - December 2019	2,941	$56.20
January - December 2020	2,204	$54.35
January - December 2021	1,815	$60.32
Basis Swaps		
January - December 2019	500	$3.00
January - December 2020	500	$3.00

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The following table illustrates the impact of derivative contracts on the Company's balance sheet:

Fair Value Derivative Contracts as of September 30, 2018

	Asset Derivatives		**Liability Derivatives**	
Derivatives not designated as hedging instruments	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Commodity price derivatives	Derivatives - current	$ 470	Derivatives - current	$ 22,845
Commodity price derivatives	Derivatives - long-term	11	Derivatives - long-term	17,188
		$ 481		$ 40,033

Fair Value Derivative Contracts as of December 31, 2017

	Asset Derivatives		**Liability Derivatives**	
Derivatives not designated as hedging instruments	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Commodity price derivatives	Derivatives - current	$ -	Derivatives - current	$ 10,837
Commodity price derivatives	Derivatives - long-term	-	Derivatives - long-term	2,387
		$ -		$ 13,224

8. Financial Instruments

Assets and liabilities measured at fair value are categorized into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon 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 in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of September 30, 2018 and December 31, 2017, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

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	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of September 30, 2018
Assets:				
NYMEX fixed price derivative contracts	$ -	$ -	$ -	$ -
NYMEX basis differential swap	-	-	481	481
Total Assets	$ -	$ -	$ 481	$ 481
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 39,555	$ -	$ 39,555
NYMEX basis differential swap	-	-	478	478
Total Liabilities	$ -	$ 39,555	$ 478	$ 40,033

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2017
Assets:				
NYMEX fixed price derivative contracts	$ -	$ -	$ -	$ -
Total Assets	$ -	$ -	$ -	$ -
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 13,208	$ -	$ 13,208
NYMEX basis differential swap	-	-	16	16
Total Liabilities	$ -	$ 13,208	$ 16	$ 13,224

The Company’s derivative contracts consisted of NYMEX-based fixed price swaps and basis differentials swaps as of September 30, 2018 and December 31, 2017. Under fixed price swaps, the Company receives a fixed price for its production and pays a variable market price to the contract counter-party. Under basis differential swaps, if the market price is above the fixed price, the Company pays the counter-party, and if the market price is below the fixed price, the counter-party pays the Company. The NYMEX-based fixed price derivative swaps and basis swaps contracts are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of NYMEX-based fixed price swaps are based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2. In order to verify the third party valuation, the Company enters the various inputs into a model and compares our results to the third party for reasonableness. The fair value of the basis differential swap instruments are based on inputs that are not as observable as the fixed price swaps. In addition to the actively quoted market price, variables such as time value, volatility and other unobservable inputs are used. Accordingly, these instruments have been classified as Level 3.

The following is additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the nine months ended September 30, 2018.

Unobservable inputs at January 1, 2018	$(16)
Changes in market value	3
Settlements during the period	16
Unobservable inputs at September 30, 2018	$3

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Nonrecurring Fair Value Measurements

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. As it relates to the Company, ASC 820-10 applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value and the initial recognition of asset retirement obligations for which fair value is used.

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's future site restoration obligations is presented in Note 1.

Other Financial Instruments

The carrying amounts of the Company's cash, cash equivalents, accounts receivable and accounts payable approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

9. Commitments and Contingencies

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At September 30, 2018, the Company was not involved in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on its financial position or results of operations.

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

The following is a discussion of our financial condition, results of operations, liquidity and capital resources. This discussion should be read in conjunction with our consolidated financial statements and the notes thereto, included in our Annual Report on Form 10-K for the year ended December 31, 2017 filed with the SEC on March 16, 2018, and the historical unaudited condensed consolidated financial statements and notes of the Company included elsewhere in this Quarterly Report.

Except as otherwise noted, all tabular amounts are in thousands, except per unit values.

Critical Accounting Policies

There have been no changes from the Critical Accounting Policies described in our Annual Report on Form 10-K for the year ended December 31, 2017.

General

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation, development and production of oil and gas in the United States. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary acreage acquisitions in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

Factors Affecting Our Financial Results

Our financial results depend upon many factors which significantly affect our results of operations including the following:

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil and gas;
- the availability of and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Arrangements. The results of our operations are highly dependent upon the prices received for our oil and gas production. The prices we receive for our production are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales of oil and gas are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

Oil and gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide supplies of oil, NGL and gas, the availability of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, we are unable to predict what changes may occur in oil, NGL and gas prices in the future. The market price of oil and condensate, NGL and gas in 2018 will impact the amount of cash generated from operating activities, which will in turn impact our financial position.

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During the nine months ended September 30, 2018, the NYMEX future price for oil averaged $66.80 per Bbl as compared to $49.39 per Bbl in the same period of 2017. During the nine months ended September 28, 2018, the NYMEX future spot price for gas averaged $2.85 per MMBtu compared to $3.21 per MMBtu in the same period of 2017. Prices closed on September 28, 2018 at $73.25 per Bbl of oil and $3.01 per MMBtu of gas, compared to closing on September 30, 2017 at $51.67 per Bbl of oil and $3.01 per MMBtu of gas. On November 5, 2018, prices closed at $62.21 per Bbl of oil and $3.56 per MMBtu of gas. If commodity prices decline, our revenue and cash flow from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If oil and gas prices decline, our revenues, profitability and cash flow from operations will also likely decrease which could cause us to alter our business plans, including reducing our drilling activities. Such declines have required, and in future periods could also require us to write down the carrying value of our oil and gas assets which would also cause a reduction in net income. The prices that we receive are also impacted by basis differentials, which can be significant, and are dependent on actual delivery points. Finally, low commodity prices will likely cause a reduction of our proved reserves, resulting in a reduction of the borrowing base under our credit facility.

The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location;
- adjustments for BTU content;
- quality of the hydrocarbons; and