ABRAXAS PETROLEUM CORP
Form 10-Q
August 09, 2018

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 June 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 August 6, 2018 was 166,713,357.

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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;
- our indebtedness and the significant amount of cash required to service our indebtedness;
- 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. Equally, 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?gp=1&SID=7aa25d3cede06103c0ecec861362497d&ty=HTML&h=L&n=pt17.3.21

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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)

	June 30, 2018 (Unaudited)	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 882	$ 1,618
Accounts receivable:		
Joint owners, net	19,399	14,218
Oil and gas production sales	13,323	17,789
Other	2	86
	32,724	32,093
Other current assets	703	778
Total current assets	34,309	34,489
Property and equipment		
Oil and gas properties, full cost method of accounting:		
Proved	999,295	923,237
Other property and equipment	39,770	39,136
Total	1,039,065	962,373

Less accumulated depreciation, depletion, amortization and impairment	(744,109)	(724,606)
Total property and equipment - net	294,956	237,767
Deferred financing fees - net	1,277	1,285
Other assets	265	265
Total assets	$ 330,807	$ 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)

	June 30, 2018 (Unaudited)	**December 31, 2017**
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 54,519	$ 45,570
Joint interest oil and gas production payable	10,121	11,502
Accrued interest	179	140
Other accrued liabilities	951	539
Derivative liabilities	21,477	10,837
Current maturities of long-term debt	261	262
Total current liabilities	87,508	68,850
Long-term debt - less current maturities	115,226	87,354
Other liabilities	132	132
Derivative liabilities long-term	10,852	2,387
Future site restoration	9,075	8,775
Total liabilities	222,793	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; 166,711,210 and 165,889,901 issued and outstanding at June 30, 2018 and December 31, 2017, respectively	1,667	1,659
Additional paid-in capital	416,944	415,471
Accumulated deficit	(310,597)	(310,822)
Total stockholders' equity	108,014	106,308
Total liabilities and stockholders' equity	$ 330,807	$ 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 June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Revenues:				
Oil	$27,472	$11,313	$63,466	$26,814
Gas	1,608	1,063	3,985	3,045
Natural gas liquids	1,835	760	4,058	2,064
	30,915	13,136	71,509	31,923
Other	1	16	37	31
	30,916	13,152	71,546	31,954
Operating costs and expenses				
Lease operating	5,730	3,421	10,299	7,539
Production and ad valorem taxes	2,485	1,158	5,598	2,778
Depreciation, depletion and amortization	8,705	4,415	18,835	9,789
General and administrative (including stock-based compensation of $879, $979, $1,466 and $1,749, respectively)	3,065	2,898	5,793	5,635
	19,985	11,892	40,525	25,741
Operating income	10,931	1,260	31,021	6,213
Other (income) expense:				
Interest income	(1)	(1)	(1)	(1)
Interest expense	1,627	501	2,956	1,008
Amortization of deferred financing fees	111	117	207	254
Loss (gain) on derivative contracts	19,763	(6,450)	27,646	(15,831)
Gain on sale of non-oil and gas assets	(15)	(102)	(12)	(102)
	21,485	(5,935)	30,796	(14,672)
(Loss) income before income tax	(10,554)	7,195	225	20,885
Income tax (expense) benefit	-	-	-	-
Net (loss) income	$(10,554)	$7,195	$225	$20,885
Net (loss) income per common share - basic	$(0.06)	$0.04	$0.00	$0.13
Net (loss) income per common share - diluted	$(0.06)	$0.04	$0.00	$0.13
Weighted average shares outstanding				
Basic	165,162	162,357	164,812	158,259

Diluted	165,162	163,805	167,715	159,942

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)

	Six Months Ended June 30, 2018			2017		
Operating Activities:						
Net income	$	225		$	20,885	
Adjustments to reconcile net income to net cash provided by operating activities:						
Gain on sale of non-oil and gas assets		(12	)		(102	)
Net loss (gain) on derivative contracts		27,646			(15,831	)
Derivative contract settlements		(9,847	)		2,000	
Depreciation, depletion and amortization		18,835			9,789	
Amortization of deferred financing fees		207			254	
Accretion of future site restoration		264			224	
Stock-based compensation		1,466			1,749	
Changes in operating assets and liabilities:						
Accounts receivable		(631	)		1,895	
Other assets		1,381			(1,041	)
Accounts payable and accrued expenses		5,752			(6,875	)
Net cash provided by operating activities		45,286			12,947	

Investing Activities						
Capital expenditures, including purchase and development of properties		(73,818	)		(25,002	)
Proceeds from the sale of oil and gas properties		82			10,653	
Proceeds from the sale of non-oil and gas assets		27			204	
Net cash used in investing activities		(73,709	)		(14,145	)
Financing Activities						
Proceeds from long-term borrowings		35,000			20,000	
Payments of long-term borrowings		(7,129	)		(82,659	)
Exercise of stock options		15			-	
Proceeds from issuance of common stock		-			65,223	
Deferred financing fees		(199	)		(714	)
Net cash provided by financing activities		27,687			1,850	
(Decrease) increase in cash and cash equivalents		(736	)		652	
Cash and cash equivalents at beginning of period		1,618			-	
Cash and cash equivalents at end of period	$	882		$	652	
Supplemental disclosure of cash flow information:						
Interest paid	$	2,577		$	802	
Non-cash investing and financing activities						
Change in capital expenditures included	$	2,267		$	15,451	

in accounts payable				
Increase in asset retirement obligation in capital expenditures		36		-
	$	2,303	$	15,451

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

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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 six month period ended June 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.

Reclassifications

Certain reclassifications have been made to the prior period financial statements to conform to the current period presentation. These reclassifications had no effect on the Company's previously reported results of operations.

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. 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. The Company does not intend to early-adopt ASU 2016-02 and other related ASUs and has not determined which transition method it will use.

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 June 30,		**Six Months Ended June 30,**	
2018	**2017**	**2018**	**2017**
$574	$635	$914	$1,069

The following table summarizes the Company's stock option activity for the six months ended June 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	(365)	$ 1.70	$ 1.18
Forfeited	(335)	$ 2.17	$ 1.55
Outstanding, June 30, 2018	7,917	$ 2.40	$ 1.71

As of June 30, 2018, there was approximately $1.0 million of unamortized compensation expense related to outstanding stock options that will be recognized from 2018 through 2021.

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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 six months ended June 30, 2018 (shares in thousands):

	Number of Shares	**Weighted Average Grant Date Fair Value Per Share**
Unvested, December 31, 2017	1,479	$ 3.43
Granted	753	$ 2.22
Vested/ Released	(733)	$ 3.15
Forfeited	(77)	$ 3.16
Unvested June 30, 2018	1,422	$ 2.95

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

Three Months Ended June 30,		**Six Months Ended June 30,**	
2018	**2017**	**2018**	**2017**
$221	$344	$468	$680

As of June 30, 2018, there was approximately $1.6 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized from 2018 through 2021.

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	(31)	$ 2.37
Unvested June 30, 2018	433	$ 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 June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
$84	$ -	$84	$ -

As of June 30, 2018, there was approximately $0.9 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 June 30, 2018 and 2017, our net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves.

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 six months ended June 30, 2018 and the year ended December 31, 2017:

	June 30, 2018	**December 31, 2017**
Beginning future site restoration obligation	$8,775	$ 8,623
New wells placed on production and other	452	1,088
Deletions related to property disposals and plugging costs	(445)	(1,551)
Accretion expense and other	264	451
Revisions and other	29	164
Ending future site restoration obligation	$9,075	$ 8,775

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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 six months ended June 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. In 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 June 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 June 30,					
	2018			**2017**		
	Oil	**Gas**	**NGL**	**Oil**	**Gas**	**NGL**
Operating Region						
Permian/Delaware Basin	$9,664	$609	$613	$1,662	$571	$312
Rocky Mountain	$15,479	$674	$1,180	$8,244	$429	$421
South Texas	$2,329	$325	$42	$1,407	$63	$27

	Six Months Ended June 30,					
	2018			**2017**		
	Oil	**Gas**	**NGL**	**Oil**	**Gas**	**NGL**
Operating Region						
Permian/Delaware Basin	$24,039	$1,528	$1,411	$4,149	$1,327	$701
Rocky Mountain	$34,719	$1,802	$2,583	$19,641	$1,300	$1,316
South Texas	$4,708	$655	$64	$3,024	$418	$47

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 June 30, 2018 and December 31, 2017, our receivables from contracts with customers were $13.3 million and $17.8 million, respectively.

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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 six months ended June 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 six months ended June 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, $255.0 million of net operating loss carryforwards 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 June 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 June 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 June 30, 2018 and December 31, 2017, respectively:

	June 30, 2018	December 31, 2017
	(In thousands)	
Senior secured credit facility	$112,000	$ 84,000
Real estate lien note	3,487	3,616
	115,487	87,616
Less current maturities	(261)	(262)
	$115,226	$ 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 June 30, 2018, $112.0 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 June 30, 2018, the Company had a borrowing base of $175.0 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 June 30, 2018, the interest rate on the credit facility was approximately 5.1% 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.

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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 June 30, 2018, the Company was in compliance with all of these financial covenants. As of June 30, 2018, the interest coverage ratio was 17.11 to 1.00, the total debt to EBITDAX ratio was 1.49 to 1.00, and our current ratio was 1.48 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 June 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 June 30, 2018, and December 31, 2017, $3.5 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands, except per share data)			
Numerator:				
Net income	$(10,554)	$7,195	$225	$20,885
Denominator for basic earnings per share - weighted-average common shares outstanding	165,162	162,357	164,812	158,259
Effect of dilutive securities: Stock options, restricted shares and performance based shares	-	1,448	2,903	1,683
Denominator for diluted earnings per share - adjusted weighted-average shares and assumed exercise of options, restricted shares and performance based shares	165,162	163,805	167,715	159,942
Net (loss) income per common share - basic	$(0.06)	$0.04	$0.00	$0.13
Net (loss) income per common share - diluted	$(0.06)	$0.04	$0.00	$0.13

Basic net (loss) 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 June 30, 2018, 3.2 million shares relating to stock options, unvested restricted shares and unvested performance based 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.

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 June 30, 2018:

	Oil - WTI	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
Fixed Swaps		
2018 July - December	4,238	$53.70
2019 January - December	2,800	$55.66
2020 January - December	2,200	$54.34

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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 June 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	$ -	Derivatives - current	$ 21,477
Commodity price derivatives	Derivatives - long-term	-	Derivatives - long-term	10,852
		$ -		$ 32,329

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 June 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):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Balance as of June 30, 2018**
Assets:				
NYMEX fixed price derivative contracts	$ -	$ -	$ -	$-
Total Assets	$ -	$ -	$ -	$-
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 32,329	$ -	$32,329
Total Liabilities	$ -	$ 32,329	$ -	$32,329

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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 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 as of June 30, 2018, and NYMEX-based fixed price swaps and a basis differential swap as of 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 a basis differential swap, if the market price is above the fixed price the Company pays the counter-party, 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 collar and 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 six months ended June 30, 2018.

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

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, restricted cash, 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.

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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 June 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 six months ended June 30, 2018, the NYMEX future price for oil averaged $65.47 per Bbl as compared to $49.95 per Bbl in the same period of 2017. During the six months ended June 30, 2018, the NYMEX future spot price for gas averaged $2.84 per MMBtu compared to $3.35 per MMBtu in the same period of 2017. Prices closed on June 30, 2018 at $74.15 per Bbl of oil and $2.92 per MMBtu of gas, compared to closing on June 30, 2017 at $46.04 per Bbl of oil and $3.04 per MMBtu of gas. On August 6, 2018, prices closed at $69.01 per Bbl of oil and $2.86 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
- gathering, processing and transportation costs.

The following table sets forth our average differentials for the six months ended June 30, 2018 and 2017:

	Oil - NYMEX		**Gas - NYMEX**	
	2018	**2017**	**2018**	**2017**
Average realized price (1)	$60.84	$44.78	$1.73	$1.85
Average NYMEX price	65.47	49.95	2.84	3.35
Differential	$(4.63)	$(5.17)	$(1.11)	$(1.50)

(1) Excludes the impact of derivative activities on oil for 2018 and for oil and gas for 2017.

At June 30, 2018, our derivative contracts consisted of NYMEX-based fixed price swaps. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party.

Our derivative contracts equate to approximately 63% of the estimated oil production from our net proved developed producing reserves (based on reserve estimates at December 31, 2017) from July 1, 2018 through December 31, 2018, 89% in 2019 and 89% in 2020. By removing a portion of price volatility on our future oil and gas production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow. We have in the past and will in the future sustain losses on our derivative contracts if market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain gains on our commodity derivative contracts. For the six months ended June 30, 2018, we realized a loss of $27.6 million, consisting of a loss of $9.8 million on closed contracts and a loss of $17.8 million related to open contracts. For the six months ended June 30, 2017, we realized a gain of $15.8 million consisting of a gain of $2.0 million on closed contracts and a gain of $13.8 million related to open contracts. We have not designated any of these derivative contracts as hedges as prescribed by applicable accounting rules.

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The following table sets forth our derivative contracts at June 30, 2018:

	Oil - WTI	
Contract Periods	**Daily Volume (Bbl)**	**Swap Price (per Bbl)**
Fixed Swaps		
2018 July - December	4,238	$53.70
2019 January - December	2,800	$55.66
2020 January - December	2,200	$54.34

At June 30, 2018, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $32.3 million.

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve report as of December 31, 2017, our average annual estimated decline rate for our net proved developed producing reserves is 38%; 21%; 13%; 11% and 10% in 2018, 2019, 2020, 2021 and 2022, respectively, 8% in the following five years, and approximately 8% thereafter. These rates of decline are estimates and actual production declines could be materially different. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures during the six months ended June 30, 2018 of $76.1 million related to our exploration and development activities as well as the acquisition of leasehold positions. We have a capital expenditure budget for 2018 of approximately $140.0 million to be funded by cash flows from operations and proceeds from our credit facility. Approximately $71.2 million of the 2018 budget is allocated to developing our Bone Spring/Wolfcamp acres in the Permian/Delaware and $33.8 million is allocated to developing our Williston Basin/Bakken/Three Forks play in North Dakota. The remaining amount is allocated to acquisitions, facilities and general corporate purposes. The 2018 capital expenditure budget is subject to change depending upon a number of factors, including prevailing and anticipated prices for oil and gas, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

The following table presents historical net production volumes for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Total Production (Mboe)	745	471	1,689	1,085
Average daily production (Boepd)	8,188	5,172	9,330	5,992
% Oil	59 %	56 %	62 %	55 %

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The following table presents our net oil, gas and NGL production, the average sales price per Bbl of oil and NGL and per Mcf of gas produced and the average cost of production per Boe of production sold, for the three and six months ended June 30, 2018 and 2017, by our major operating regions:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Oil Production (Bbls)				
Rocky Mountain	247	195	578	450
Permian	158	37	394	87
South Texas	34	29	71	62
Total	439	261	1,043	599
Gas Production (Mcf)				
Rocky Mountain	520	395	1,045	908
Permian	452	291	971	571
South Texas	146	25	288	171
Total	1,118	711	2,304	1,650
NGL Production (Bbl)				
Rocky Mountain	84	69	179	168
Permian	34	20	80	40
South Texas	2	2	3	3
Total	120	91	262	211
Average sales price per Bbl of oil (1)				
Rocky Mountain	$62.73	$42.25	$60.05	$43.63
Permian	$61.11	$45.30	$61.04	$47.90
South Texas	$68.84	$47.46	$66.21	$48.83
Composite	$62.62	$43.27	$60.84	$44.78
Average sales price per MCF of gas (1)				
Rocky Mountain	$1.30	$1.08	$1.72	$1.43
Permian	$1.35	$1.96	$1.58	$2.32
South Texas	$2.22	$2.54	$2.27	$2.44
Composite	$1.44	$1.49	$1.73	$1.85
Average sales price per Bbl of NGL				
Rocky Mountain	$14.10	$6.10	$14.45	$7.85
Permian	$17.78	$15.76	$17.67	$17.39
South Texas	$23.12	$15.45	$21.53	$15.84
Composite	$15.29	$8.39	$15.51	$9.78
Average cost of production per Boe produced (2)				
Rocky Mountain	$7.66	$5.64	$5.97	$5.17
Permian	$6.83	$9.37	$5.15	$9.25
South Texas	$13.98	$20.78	$13.62	$18.30
Composite	$7.87	$7.62	$6.22	$7.13

(1) Before the impact of oil hedging activities in 2018 and oil and gas hedging activities in 2017.

(2) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

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Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flow from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, monetizing of derivative instruments, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. In January 2017, we completed a stock offering of 28.8 million shares of common stock for net proceeds of approximately $65.2 million. The net proceeds from this offering were used to repay borrowings under our credit facility. As of June 30, 2018, our borrowing base was $175.0 million with $63.0 million of availability under our credit facility.

Borrowings and Interest. At June 30, 2018, we had a total of $112.0 million outstanding under our credit facility and total indebtedness of $115.5 million (including the current portion). If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

Exploration and Development Activity. We believe that our high quality asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2017, we operated properties accounting for approximately 96% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 67% of our estimated proved reserves on a Boe basis at December 31, 2017 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may be unable to acquire or develop additional reserves or develop our existing undeveloped reserves, in which case our results of operations and financial condition could be adversely affected.

Operational Update

In North Dakota, seven new wells were successfully fracture stimulated and placed on production. Due to our conservative flowback protocol, these wells have not yet achieved peak 30 day rates. On the Yellowstone NE Central pad, three wells, one in the Middle Bakken and two in the Three Forks, all with approximate 10,000 foot laterals, are currently flowing back at a 2 stream average of 1,418 boe/d per well (81% oil). This current rate is approximately 55% above our previously published type curves. Abraxas owns a 51.6% working interest in this pad. On the Lillibridge NE pad, four wells with approximate 10,000 foot laterals, two each in the Middle Bakken and Three Forks, were successfully completed and are flowing back on our conservative protocol without yet achieving peak 30 day rates, at a 2 stream average of 771 boe/d per well (81% oil). These wells are producing on or slightly below our previously published type curves. This performance was not unexpected, as these are infill wells next to wells that have been on production approximately five years. Abraxas owns an average of approximately 27% in these wells. Our Company owned drilling rig, Raven Rig #1, successfully drilled four new wells with approximate 10,000 foot laterals on the Ravin NE Central pad and is currently drilling laterals in four wells on the Ravin NE pad. These eight wells are scheduled to be fracture stimulated starting in mid-September. Abraxas owns an average 46.8% working interest in these eight wells.

In the Delaware Basin of West Texas, specifically in Ward County, the Company successfully completed and placed on production our four well Caprito 99 downspacing test pad. These wells with approximate 4,800 foot laterals have been on production for approximately one month and due to our conservative flowback protocol have not achieved peak rates, which from past experience we expect to achieve between 45 to 60 days from initial oil production. The wells are currently producing at a 2 stream average of 668 boe/d per well (88% oil). All wells are producing above our previously published type curves. The two wells closest to our original section 99 producer, which has been on production almost two years, are not as strong with rate or pressure than the two wells further away, showing some parent-child influence, the degree of which will only be determined with production data over the next several months. We collected a considerable amount of analytical data including micro seismic and tracers to help analyze the amount of well to well interference, if any, between these wells which were spaced 660 feet apart in the same zone as opposed to our previous spacing of 1,320 feet between wells in the same zone. This data along with production data will be analyzed over the next several months to help determine proper spacing for future development. Abraxas owns a 57.8% working interest in this pad.

Five miles to the north, still in Ward County, the Company successfully drilled the two well Greasewood pad with approximate 4,800 foot laterals in the Upper Wolfcamp A-1 and A-2. These wells are currently being fracture stimulated with flowback expected around mid-August. Abraxas owns a 100% working interest in the Greasewood section. Five miles south of Caprito, also in Ward County, we have successfully drilled the two well Mesquite pad, with approximate 4,800 foot laterals in the Upper Third Bone Spring (a new zone for Abraxas) and in the Lower Third Bone Spring (successfully tested in Caprito 82). Abraxas owns a 72% working interest in the Mesquite pad which is scheduled to be fracture stimulated in mid-September. The rig is currently moving approximately seven miles south but still in Ward County, to drill an approximate 4,800 foot lateral to test the Upper Wolfcamp A-1, in our Pecan 47 unit, in which Abraxas owns a 100% working interest.

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Results of Operations

Selected Operating Data. The following table sets forth operating data from continuing operations for the periods presented.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Operating revenue (1):				
Oil sales	$27,472	$11,313	$63,466	$26,814
Gas sales	1,608	1,063	3,985	3,045
NGL sales	1,835	760	4,058	2,064
Other	1	16	37	31
Total operating revenues	$30,916	$13,152	$71,546	$31,954
Operating income	$10,931	$1,260	$31,021	$6,213
Oil sales (MBbls)	439	261	1,043	599
Gas sales (MMcf)	1,118	711	2,304	1,650
NGL sales (MBbls)	120	91	262	211
Oil equivalents (Mboe)	745	471	1,689	1,085
Average oil sale price (per Bbl)(1)	$62.62	$43.27	$60.84	$44.78
Average gas sales price (per Mcf)(1)	$1.44	$1.49	$1.73	$1.85
Average NGL price (per Bbl)	$15.29	$8.39	$15.51	$9.78
Average oil equivalent sales price (Boe)(1)	$41.49	$27.91	$42.34	$29.43

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(1) Revenue and average sales prices are before the impact of hedging activities.

Comparison of Three Months Ended June 30, 2018 to Three Months Ended June 30, 2017

Operating Revenue. During the three months ended June 30, 2018, operating revenue increased to $30.9 million from $13.2 million for the same period of 2017. The increase in revenue was due to higher sales volumes for all products and higher oil and NGL prices during the three months ended June 30, 2018 as compared to the same period of 2017. Higher sales volumes contributed $8.7 million to operating revenue for the three months ended June 30, 2018. Higher realized commodity prices for oil and NGL contributed $9.1 million to operating revenue, of which $8.5 million was attributable to oil.

Oil sales volumes increased to 439 MBbl during the three months ended June 30, 2018 from 261 MBbl for the same period of 2017. The increase in oil sales volume was primarily due to new wells brought on line since the second quarter of 2017, offset by natural field declines and property sales. New wells brought on line since the second quarter of 2017 contributed 225 MBbl for the three months ended June 30, 2018. Gas sales volumes increased to 1,118 MMcf for the three months ended June 30, 2018 from 711 MMcf for the same period of 2017. The increase in gas production was due to new wells brought on line since the second quarter of 2017 which contributed 249 MMcf for the three months ended June 30, 2018. NGL sales volumes increased to 120 MBbl for the three months ended June 30, 2018 from 91 MBbl for the same period of 2017. The increase in NGL sales was primarily due to more gas production in the Permian Basin and Rocky Mountain regions which have a high NGL content.

Lease Operating Expenses ("LOE"). LOE for the three months ended June 30, 2018 increased to $5.7 million from $3.4 million for the same period in 2017. The increase in LOE was primarily due to higher cost of services and new wells brought onto production since June 30, 2017. LOE per Boe for the three months ended June 30, 2018 was $7.69 compared to $7.27 for the same period of 2017. The increase per Boe was due to higher costs offset by higher sales volumes for the three months ended June 30, 2018 as compared to the same period of 2017.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended June 30, 2018 increased to $2.5 million from $1.2 million for the same period in 2017. The increase was primarily due to higher commodity prices and production volumes. Production and ad valorem taxes for the three months ended June 30, 2018 were 8% of total oil, gas and NGL sales compared to 9% for the same period of 2017. The decrease in the percentage of taxes of total oil, gas and NGL sales was due to increased production in Texas which has a lower tax rate.

General and Administrative ("G&A") Expense. G&A expenses, excluding stock-based compensation, increased to $2.2 million for the three months ended June 30, 2018 compared to $1.9 million for the same period of 2017. G&A expense per Boe, excluding stock-based compensation, was $2.93 for the quarter ended June 30, 2018 compared to $4.08 for the same period of 2017. The decrease per Boe was primarily due to higher sales volumes.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options' vesting period. In addition to options, restricted shares of the Company's common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the three months ended June 30, 2018 stock-based compensation expense was $0.9 million compared to $1.0 million for the same period of 2017.

Depreciation, Depletion and Amortization ("DD&A") Expense. DD&A expense for the three months ended June 30, 2018 increased to $8.7 million from $4.4 million for the same period of 2017. The increase was primarily due to increased production for the three months ended June 30, 2018 as compared to the same period of 2017 as well as increased future development costs included in our internally prepared June 30, 2018 reserve report. DD&A expense per Boe for the three months ended June 30, 2018 was $11.68 compared to $9.38 in 2017. The increase was primarily the result higher future development costs.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future revenues from proved reserves, 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, related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of June 30, 2018, and June 30, 2017, our net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved reserves are revised downward, a further write-down of the carrying value of our oil and gas properties may be required.

Interest Expense. Interest expense for the three months ended June 30, 2018 increased to $1.6 million compared to $0.5 million for the same period of 2017. The increase in interest expense in 2018 was due to higher levels of debt during the three months ended June 30, 2018 as compared to the same period in 2017 as well as higher interest rates in 2018 as compared to 2017. The average interest rate during the three months ended June 30, 2018 was 5.1% compared to 3.8% during the same period of 2017.

Loss (Gain) on Derivative Contracts. Derivative gains or losses are determined by actual derivative settlements during the period and on the periodic mark to market valuation of derivative contracts in place. We have elected not to apply hedge accounting to our derivative contracts; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of NYMEX-based fixed price swaps as of June 30, 2018, and NYMEX-based fixed price swaps, basis differential swaps and collars contracts as of June 30, 2017. The net estimated value of our commodity derivative contracts was a net liability of approximately $32.3 million as of June 30, 2018. When our derivative contract prices are higher than prevailing market prices, we incur gains and, conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the three months ended June 30, 2018, we recognized a loss on our commodity derivative contracts of $19.8 million, consisting of a loss on closed contracts of $6.1 million and a loss of $13.7 million related to open contracts. For the three months ended June 30, 2017, we recognized a gain on our commodity derivative contracts of $6.5 million, consisting of a gain of $1.4 million on closed contracts and a gain of $5.1 million related to open contracts.

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Income Tax Expense. For the three months ended June 30, 2018 and 2017 there was no income tax expense recognized as a result of a loss for the period and our NOL carryforwards.

Comparison of Six Months Ended June 30, 2018 to Six Months Ended June 30, 2017

Operating Revenue. During the six months ended June 30, 2018, operating revenue increased to $71.5 million from $32.0 million for the same period of 2017. The increase in revenue was due to higher sales volumes for all products and higher oil and NGL prices during the six months ended June 30, 2018 as compared to the same period of 2017. Higher sales volumes contributed $21.8 million to operating revenue for the six months ended June 30, 2018. Higher realized commodity prices for oil and NGL contributed $18.0 million to operating revenue of which $16.8 million was attributable to oil. Lower gas prices had a negative impact on revenue of approximately $0.2 million, for the six months ended June 30, 2018.

Oil sales volumes increased to 1,043 MBbl during the six months ended June 30, 2018 from 599 MBbl for the same period of 2017. The increase in oil sales volume was primarily due to new wells brought on line since the second quarter of 2017, offset by natural field declines and property sales. New wells brought on line since the second quarter of 2017 contributed 570 MBbl for the six months ended June 30, 2018. Gas sales volumes increased to 2,304 MMcf for the six months ended June 30, 2018 from 1,650 MMcf for the same period of 2017. The increase in gas production was due to new wells brought on line since the second quarter of 2017 which contributed 565 MMcf for the six months ended June 30, 2018. NGL sales volumes increased to 262 MBbl for the six months ended June 30, 2018 from 211 MBbl for the same period of 2017. The increase in NGL sales was primarily due to more gas production in the Permian Basin and Rocky Mountain regions which have a high NGL content.

Lease Operating Expenses ("LOE"). LOE for the six months ended June 30, 2018 increased to $10.3 million from $7.5 million for the same period in 2017. The increase in LOE was primarily due to higher cost of services and new wells brought onto production since June 30, 2017. LOE per Boe for the six months ended June 30, 2018 was $6.10 compared to $6.95 for the same period of 2017. The decrease per Boe was due to higher costs offset by higher sales volumes for the six months ended June 30, 2018 as compared to the same period of 2017.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the six months ended June 30, 2018 increased to $5.6 million from $2.8 million for the same period in 2017. The increase was primarily due to higher commodity prices and production volumes. Production and ad valorem taxes for the six months ended June 30, 2018 were 8% of total oil, gas and NGL sales compared to 9% for the same period of 2017. The decrease in the percentage of taxes of total oil, gas and NGL sales was due to increased production in Texas which has a lower tax rate.

General and Administrative ("G&A") Expense. G&A expenses, excluding stock-based compensation, increased to $4.3 million for the six months ended June 30, 2018 compared to $3.9 million for the same period of 2017. G&A expense per Boe, excluding stock-based compensation, was $2.56 for the quarter ended June 30, 2018 compared to $3.58 for the same period of 2017. The decrease per Boe was primarily due to higher G&A expense offset by higher sales volumes.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options' vesting period. In addition to options, restricted shares of the Company's common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the six months ended June 30, 2018 stock-based compensation expense was $1.5 million compared to $1.7 million for the same period of 2017.

Depreciation, Depletion and Amortization ("DD&A") Expense. DD&A expense for the six months ended June 30, 2018 increased to $18.8 million from $9.8 million for the same period of 2017. The increase was primarily due to increased production for the six months ended June 30, 2018 as compared to the same period of 2017 as well as increased future development costs included in our internally prepared June 30, 2018 reserve report. DD&A expense per Boe for the six months ended June 30, 2018 was $11.15 compared to $9.02 in 2017. The increase was primarily the result higher future development costs.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future revenues from proved reserves, 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. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of June 30, 2018, and June 30, 2017, our net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved reserves are revised downward, a further write-down of the carrying value of our oil and gas properties may be required.

Interest Expense. Interest expense for the six months ended June 30, 2018 increased to $3.0 million compared to $1.0 million for the same period of 2017. The increase in interest expense in 2018 was due to higher levels of debt during the six months ended June 30, 2018 as compared to the same period in 2017 as well as higher interest rates in 2018 as compared to 2017. The average interest rate during the six months ended June 30, 2018 was 5.0% compared to 3.2%

Loss (Gain) on Derivative Contracts. Derivative gains or losses are determined by actual derivative settlements during the period and on the periodic mark to market valuation of derivative contracts in place. We have elected not to apply hedge accounting to our derivative contracts; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of NYMEX-based fixed price swaps as of June 30, 2018, and NYMEX-based fixed price swaps, basis differential swaps and collars contracts as of June 30, 2017. The net estimated value of our commodity derivative contracts was a net liability of approximately $32.3 million as of June 30, 2018. When our derivative contract prices are higher than prevailing market prices, we incur gains and, conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the six months ended June 30, 2018, we recognized a loss on our commodity derivative contracts of $27.6 million, consisting of a loss on closed contracts of $9.8 million and a loss of $17.8 million related to open contracts. For the six months ended June 30, 2017, we recognized a gain on our commodity derivative contracts of $15.8 million, consisting of a gain of $2.0 million on closed contracts and a gain of $13.8 million related to open contracts.

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Income Tax Expense. For the six months ended June 30, 2018 and 2017 there was no income tax expense recognized as a result of our NOL carryforwards.

Liquidity and Capital Resources

General. The oil and gas industry is a highly capital intensive and cyclical business. Our capital requirements are driven principally by our obligations to service debt and to fund the following:

- the development and exploration of existing properties, including drilling and completion costs of wells;
- acquisition of interests in additional oil and gas properties; and
- production and transportation facilities.

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to grow the business through the development of existing properties and the acquisition of new properties.

Our principal sources of capital are cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, monetizing of derivative contracts and if appropriate opportunities are available, the sale of debt or equity securities, although we may not be able to complete any such transactions on terms acceptable to us, if at all. Based upon current oil, gas and NGL price expectations and our commodity derivatives positions, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient liquidity to fund our operations for the remainder of 2018 including our planned capital expenditures.

Capital Expenditures. Capital expenditures for the six months ended June 30, 2018 and 2017 were $76.1 million and $40.5 million, respectively.

The table below sets forth the components of these capital expenditures:

Six Months
Ended June 30,

	2018	2017
	(In thousands)	
Expenditure category:		
Exploration/Development	$53,623	$40,149
Acquisitions	21,769	-
Facilities and other	729	304
Total	$76,121	$40,453

During the six months ended June 30, 2018 and 2017, our expenditures were primarily for development of our existing properties and the acquisition of leasehold positions. Expenditures during the six months ended June 30, 2018 of $76.1 million included approximately $21.8 million for the acquisition of mineral acres in Winkler and Ward County, Texas. Our capital expenditure budget for 2018 is approximately $140.0 million of which approximately $71.2 million is allocated to acquiring additional acreage and developing the Company's Bone Spring/Wolfcamp acreage in the Permian/Delaware Basin. The budget also allocates approximately $33.8 million for developing our Williston Basin Bakken/Three Forks play in North Dakota, with the remaining amount allocated to acquisitions, facilities and general corporate purposes. The 2018 capital expenditure budget is subject to change depending upon a number of factors, including the availability of sufficient capital resources including under our credit facility, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our exploitation efforts, our financial results and our ability to obtain permits for drilling locations. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

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Sources of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	Six Months Ended June 30,	
	2018	2017
	(In thousands)	
Net cash provided by operating activities	$45,286	$12,947
Net cash used in investing activities	(73,709)	(14,145)
Net cash provided by financing activities	27,687	1,850
	$ (736)	$ 652

Operating activities for the six months ended June 30, 2018 provided $45.3 million in cash compared to providing $13.0 million in the same period of 2017. Operating income, excluding the impact of derivative losses, and net changes in operating assets and liabilities accounted for most of these funds. Investing activities used $73.7 million during the six months ended June 30, 2018 for the development of our existing properties and leasehold acquisitions. Cash expenditures for the six months ended June 30, 2018 exclude an increase in the accounts payable balance related to capital expenditures of $2.3 million, resulting in actual capital expenditures incurred during the period of $76.1 million. Investing activities used $14.1 million during the six months ended June 30, 2017, as capital expenditures of $25.0 million were offset by proceeds from sales of oil and gas properties and non-oil and gas assets of $10.7 million and $0.2 million, respectively. Actual capital expenditures incurred for the six months ended June 30, 2017 were $40.5 million, consisting of $25.0 million in cash expenditures and an increase in accounts payable related to capital expenditures of $15.5 million. Financing activities provided $27.7 million for the six months ended June 30, 2018 compared to $1.9 million for the same period of 2017. Funds provided during the six months ended June 30, 2018 were primarily borrowings under our credit facility, offset by payments of borrowings under our credit facility. Funds provided during the six months ended June 30, 2017 were primarily proceeds from the issuance of 28.8 million shares of common stock in January 2017 for net proceeds of approximately $65.2 million which were used to repay borrowings under our credit facility.

Future Capital Resources. Our principal sources of capital going forward are cash flows from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, monetizing derivative instruments and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all.

Cash from operating activities is dependent upon commodity prices and production volumes. Depressed commodity prices have reduced, and further decreases in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future, we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including availability of capital and the risk that no commercially productive oil and gas reservoirs will be found. If our proved reserves decline in the future, our production could also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility could also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 67% of our total estimated proved reserves on a Boe basis at December 31, 2017 were classified as undeveloped.

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We have in the past, and may in the future, sell producing properties. We have also sold debt and equity securities in the past, and may sell additional debt and equity securities in the future when the opportunity presents itself.

Contractual Obligations. We are committed to making cash payments in the future on the following types of agreements:

- Long-term debt, and
- Operating leases for office facilities.

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of June 30, 2018:

	Payments due in the twelve month periods ended:				
Contractual Obligations (In thousands)	Total	June 30, 2019	June 30, 2020-2021	June 30, 2022-2023	Thereafter
Long-term debt (1)	$115,487	$261	$ 112,562	$ 620	$ 2,044
Interest on long-term debt (2)	14,743	5,879	8,624	235	5
Lease obligations (3)	9	9	-	-	-
Total	$130,239	$6,149	$ 121,186	$ 855	$ 2,049

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(1) These amounts represent the balances outstanding under our credit facility and the real estate lien note. These payments assume that we will not borrow additional funds.

(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.

(3) Lease on office space in Dickinson, North Dakota, which expires on October 31, 2018.

We maintain a reserve for costs associated with future site restoration related to the retirement of tangible long-lived assets. At June 30, 2018, our reserve for these obligations totaled $9.0 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Condensed Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At June 30, 2018, we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have, or are reasonably likely to have a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At June 30, 2018, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Long-Term Indebtedness.

Long-term debt consisted of the following:

	June 30, 2018	**December 31, 2017**
	(In thousands)	
Senior secured credit facility	$112,000	$ 84,000
Real estate lien note	3,487	3,616
	115,487	87,616
Less current maturities	(261)	(262)
	$115,226	$ 87,354

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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 June 30, 2018, $112.0 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 June 30, 2018, we had a borrowing base of $175.0 million. The borrowing base is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our 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 our 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 we are 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 we must pledge additional oil and gas properties or other assets as collateral. We do not currently have any substantial unpledged assets and we may not have the financial resources to make any mandatory principal payments. In addition, a reduction of the borrowing base could also cause us to fail to be in compliance with the financial covenants described below. The borrowing base will be automatically reduced in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest at (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 June 30, 2018, the interest rate on the credit facility was approximately 5.10% 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. We are permitted to terminate the credit facility and are 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 our 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 our and our subsidiary guarantors' material property and assets. The collateral is required to include properties comprising at least 90% of the PV-10 of our proven reserves. We have also granted our lenders a security interest in our headquarters building.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are 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. We are 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 our headquarters building and obligations with respect to surety bonds and derivative contracts.

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At June 30, 2018, we were in compliance with all of these financial covenants. As of June 30, 2018, the interest coverage ratio was 17.11 to 1.00, the total debt to EBITDAX ratio was 1.49 to 1.00, and our current ratio was 1.48 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 June 30, 2018, we were in compliance with all of the terms of our credit facility.

Real Estate Lien Note

We have 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 June 30, 2018, and December 31, 2017, $3.5 million and $3.6 million, respectively was outstanding on the note.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. We have entered into commodity swaps on approximately 63% of our estimated oil production from our net proved developed producing reserves (based on reserve estimates at December 31, 2017) from January 1, 2018 through December 31, 2018, 89% for 2019 and 89% for 2020.

By removing a portion of price volatility on our future oil and gas production, we believe that we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained, and in the future, will sustain, losses on our derivative contracts when market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain gains on our commodity derivative contracts.

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If the disparity between our contract prices and market prices continues, we will sustain gains or losses on our derivative contracts. While gains and losses resulting from the periodic mark to market of our open contracts do not impact our cash flow from operations, gains and losses from settlements of our closed contracts do impact our cash flow from operations.

In addition, as our derivative contracts expire over time, we expect to enter into new derivative contracts at then-current market prices. If the prices at which we hedge future production are significantly lower than our existing derivative contracts, our future cash flow from operations would likely be materially lower.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for our oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the six months ended June 30, 2018, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $3.1 million. If commodity prices decline from current levels, the impact on operating revenues and cash flow, could be much more significant. However, we do have derivative contracts in place that will mitigate the impact of low commodity prices.

Derivative Instrument Sensitivity

At June 30, 2018, the aggregate fair market value of our commodity derivative contracts was a net liability of approximately $32.3 million. The fair market value of our commodity derivative contracts is sensitive to changes in the market price for oil and gas. When our derivative contract prices are higher than prevailing market prices, we incur gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of June 30, 2018, we had $112.0 million of outstanding indebtedness under our credit facility. Outstanding amounts under the credit facility bear interest at (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, 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 2.5%-3.5%, depending on the utilization of the borrowing base. At June 30, 2018, the interest rate on the credit facility was approximately 5.10% assuming LIBOR borrowings. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.1 million on an annual basis, based on our outstanding indebtedness as of June 30, 2018.

Item 4. Controls and Procedures.

As of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer carried out an evaluation of the effectiveness of Abraxas' "disclosure controls and procedures" (as defined in the Securities Exchange Act of 1934 Rules 13a-15(e)and 15d-15(e)) and concluded that the disclosure controls and procedures were effective.

There were no changes in our internal controls over financial reporting during the six months ended June 30, 2018 covered by this report that could materially affect, or are reasonably likely to materially affect, our financial reporting.

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PART II

Item 1. Legal Proceedings.

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 June 30, 2018, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse impact on its financial position or results of operations.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2017, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing Abraxas. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

None

Item 3. Defaults Upon Senior Securities.

None

Item 4. Mine Safety Disclosure.

Not applicable

Item 5. Other Information.

None

Item 6. Exhibits.

(a) Exhibits

Exhibit 31.1 Certification - Robert L.G. Watson, CEO
Exhibit 31.2 Certification - G. William Krog, Jr., Interim CFO
Exhibit 32.1 Certification pursuant to 18 U.S.C. Section 1350 - Robert L.G. Watson, CEO
Exhibit 32.2 Certification pursuant to 18 U.S.C. Section 1350 - G. William Krog, Jr. Interim CFO

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ABRAXAS PETROLEUM CORPORATION

SIGNATURES

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

Date August 9, 2018	**By:** /s/Robert L.G. Watson **ROBERT L.G. WATSON,** **President and** **Principal Executive Officer**
Date August 9, 2018	**By**: /s/G. William Krog, Jr. **G. WILLIAM KROG, JR.,** **Vice President and** **Principal Financial and Accounting Officer**