Janus Resources, Inc.
Form 10-Q
November 09, 2011

United States
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2011

Or

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

For the transition period from _____ to _____

Commission File Number: 000-30156

JANUS RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Nevada (State or other jurisdiction of incorporation)	98-0170247 (I.R.S. Employer Identification No.)
430 Park Avenue, Suite 702, New York, NY (Address of principal executive offices)	10022 (Zip Code)

800-755-5815
(Registrant's telephone number, including area code)

(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 such filing requirements for the past 90 days.
Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 ¨ Not Applicable x

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	x

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

As of November 7, 2011, the registrant had 63,075,122 shares of its common stock, par value $0.00001 per share, issued and outstanding.

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(Formerly Entheos Technologies, Inc.)

FORM 10-Q
For the Quarterly Period Ended September 30, 2011

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

JANUS RESOURCES, INC.
(formerly Entheos Technologies, Inc.)
CONSOLIDATED BALANCE SHEETS

	(Unaudited) September 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 964,448	$ 2,052,305
Accounts receivable	16,091	2,615
Prepaid expenses	3,870	-
Total current assets	984,409	2,054,920
Oil and gas properties		
Proven properties	433,522	432,089
Unproven properties	97,838	103,087
Accumulated depreciation, depletion, amortization and impairment	(511,517)	(508,583)
Oil and gas properties, net	19,843	26,593
Mineral properties	484,100	-
Total assets	$ 1,488,352	$ 2,081,513
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities		
Accounts payable and accrued liabilities	$ 24,518	$ 9,404
Accounts payable - related parties	8,488	13,270
Warrant liability	888,941	5,248,041
Total current liabilities	921,947	5,270,715
Long-term liabilities		
Asset retirement obligation	54,596	52,558
Total liabilities	976,543	5,323,273
Stockholders' equity (deficit)		
Preferred stock: $0.0001 par value: Authorized: 10,000,000 shares Issued and outstanding: nil	-	-
Common stock: $0.00001 par value: Authorized: 200,000,000 shares Issued and outstanding: 63,075,122 shares (2010: 63,075,122)	631	631
Additional paid-in capital	5,462,236	5,462,236
Accumulated deficit	(4,912,476)	(8,704,627)
Accumulated other comprehensive income (loss)	(38,582)	-

Total stockholders' equity (deficit)	511,809	(3,241,760)
Total liabilities and stockholders' equity (deficit)	$ 1,488,352	$ 2,081,513

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

JANUS TECHNOLOGIES, INC.
(Formerly Entheos Technologies, Inc.)
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Revenue				
Oil and gas sales	$ 6,095	$ 6,150	$ 23,808	$ 30,237
Expenses				
Lease operating expenses	5,319	4,247	16,080	15,886
Exploration costs	39,828	-	141,763	-
General and administrative expenses	151,993	62,021	432,121	193,536
Impairment and depreciation	331	12,113	2,934	52,996
Total operating expenses	197,471	78,381	592,898	262,418
Operating Loss	(191,376)	(72,231)	(569,090)	(232,181)
Other income / (expense)				
Change in fair value of warrant liability	1,358,452	1,068,044	4,359,100	1,083,644
Gain on disposal of assets	2,141	-	2,141	-
	1,360,593	1,068,044	4,361,241	1,083,644
Net income attributable to common stockholders	$ 1,169,217	$ 995,813	$ 3,792,151	$ 851,463
Earnings per share - basic				
Income per common share	$ 0.02	$ 0.02	$ 0.06	$ 0.01
Weighted average shares outstanding	63,075,122	63,075,122	63,075,122	63,075,122
Earnings per share - diluted				
Income per common share	$ 0.02	$ 0.02	$ 0.06	$ 0.01
Weighted average shares and dilutive potential common shares outstanding	64,501,373	63,075,122	64,465,803	63,075,122

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

JANUS RESOURCES, INC.
(Formerly Entheos Technologies, Inc.)
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT) AND COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Common Stock		Additional paid-in capital	Comprehensive income	Accumulated earnings (deficit)	Accumulated other comprehensive income (loss)	Total stockholders' equity (deficit)
	Shares	Amount					
Balance, December 31, 2010	63,075,122	$ 631	$ 5,462,236		$ (8,704,627)	$ -	$ (3,241,760)
Comprehensive income:							
Net income, September 30, 2011	-	-	-	$ 3,792,151	3,792,151	-	3,792,151
Foreign currency translation adjustment	-	-	-	(38,582)	-	(38,582)	(38,582)
Total comprehensive income				$ 3,753,569			
Balance, September 30, 2011	63,075,122	$ 631	$ 5,462,236		$ (4,912,476)	$ (38,582)	$ 511,809

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

JANUS RESOURCES, INC.
(formerly Entheos Technologies, Inc.)
CONSOLDIATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine months ended September 30, 2011	2010
Cash flows from operating activities		
Net income	$ 3,792,151	$ 851,463
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Impairment and depreciation	2,934	52,996
Stock-based compensation	-	(36,138)
Accretion of asset retirement obligation	2,038	1,906
Change in fair value of warrant liability	(4,359,100)	(1,083,644)
Gain on disposal of assets	(2,141)	-
Changes in operating assets and liabilities:		
Accounts receivable	(13,476)	7,327
Inventory	-	(2,507)
Prepaid expenses	(3,870)	-
Accounts payable & accrued liabilities including related party payables	10,332	(11,929)
Net cash flows from operating activities	(571,132)	(220,526)
Cash flows from investing activities		
Acquisition of oil and gas properties	(1,433)	(8,523)
Proceeds from disposal of oil and gas properties	7,390	-
Acquisition of mineral properties	(484,100)	-
Net cash flows from investing activities	(478,143)	(8,523)
Effect of exchange rate changes on cash	(38,582)	-
Decrease in cash and cash equivalents	(1,087,857)	(229,049)
Cash and cash equivalents, beginning of period	2,052,305	2,409,770
Cash and cash equivalents, end of period	$ 964,448	$ 2,180,721
Supplemental disclosure of cash flow information:		
Interest paid in cash	$ -	$ -
Income tax paid in cash	$ -	$ -

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

JANUS RESOURCES, INC.
(Formerly Entheos Technologies, Inc.)
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization and Nature of Operations

Janus Resources, Inc. (formerly Entheos Technologies, Inc.) (the "Company") is in the business of location, acquisition, exploration and, if warranted, development of both mineral exploration properties and oil and gas properties. The Company pursues oil and gas prospects in partnership with oil and gas companies with exploration, development and production expertise. Currently, its interests consist of non-operating, minority working interests in oil and gas properties. On June 8, 2011, the Company completed the acquisition of the Fostung tungsten property, located in Foster Township, Sudbury, Ontario, Canada.

The Company's general business strategy is to acquire mineral properties and oil and gas properties either directly or through the acquisition of operating entities. Its continued operations and the recoverability of property costs are dependent upon the existence of economically recoverable mineral and oil and gas reserves, the confirmation of its interest in the underlying properties, its ability to obtain necessary financing to complete development, and future profitable production.

Incorporated under the laws of the State of Nevada, the Company has an authorized capital of 200,000,000 shares of $0.00001 par value common stock, of which 63,075,122 shares are outstanding and 10,000,000 shares of $0.0001 par value preferred stock, of which none are outstanding as of September 30, 2011.

Effective January 5, 2011, the Company changed its name from "Entheos Technologies, Inc." to "Janus Resources, Inc." so as to more fully reflect the Company's operations.

Note 2. Accounting Policies

Basis of Presentation and Principles of Accounting

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and do not include all information and disclosures required by generally accepted accounting principles ("GAAP") in the United States ("U.S."), and pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC"). Therefore, this information should be read in conjunction with Janus Resources, Inc. financial statements and notes contained in its 2010 Annual Report on Form 10-K. The information furnished herein reflects all adjustment that are, in the opinion of management, necessary for the fair statement of the results for the interim periods reported. All such adjustments are, in the opinion of management, of a normal recurring nature. Operating results for the nine month period ended September 30, 2011, are not necessarily indicative of the results that may be expected for the year ending December 31, 2011.

In preparing the accompanying consolidated financial statements, the Company has evaluated information about subsequent events that became available to them through the date the financial statements were issued. This information relates to events, transactions or changes in circumstances that would require us to adjust the amounts reported in the financial statements or to disclose information about those events, transactions or changes in circumstances.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiary, Fostung Resources, Ltd (“Fostung”). Collectively, they are referred to herein as “the Company”. Significant intra-entity accounts and transactions have been eliminated. Fostung Resources, Ltd. was incorporated on May 10, 2011 in Ontario, Canada.

The Company accounts for its undivided interest in oil and gas properties using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in its financial statements.

Applicable Accounting Guidance

Any reference in these notes to applicable accounting guidance is meant to refer to the authoritative non-governmental United States GAAP as found in the Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC").

Accounting 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 the reported amounts of revenues and expenses during the reporting period. Management’s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, consultants and historical experience in similar matters. The more significant reporting areas impacted by management’s judgments and estimates are accruals related to oil and gas sales and expenses; estimates used in the impairment of oil and gas properties; and the estimated future timing and cost of asset retirement obligations.

Actual results could differ from the estimates as additional information becomes known. The carrying values of oil and gas properties are particularly susceptible to change in the near term. Changes in the future estimated oil and gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analysis could have a significant impact on the future results of operations.

Full Cost Method of Accounting for Oil and Gas Properties

The Company has elected to utilize the full cost method of accounting for its oil and gas activities. In accordance with the full cost method of accounting, all costs associated with acquisition, exploration, and development of oil and gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized.

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves once proved reserves are determined to exist. The Company has not yet obtained reserve reports. Management is assessing production data to determine the feasibility of obtaining reserves studies. At September 30, 2011, there were no capitalized costs subject to amortization.

Oil and gas properties without estimated proved reserves are not amortized until proved reserves associated with the properties can be determined or until impairment occurs. As a result of management's impairment analysis, the Company recorded an impairment loss of $2,934 and $19,621 during the nine month periods ended September 30, 2011 and 2010, respectively. The impairment is similar to amortization and therefore is not added to the costs of properties being amortized. See "Note 6. Fair Value Measurement" for further information.

Sales of oil and gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income. The Company has not sold any oil and gas properties.

Full Cost Ceiling Test

At the end of each quarterly reporting period, the unamortized costs of oil and gas properties are subject to a "ceiling test" which basically limits capitalized costs to the sum of the estimated future net revenues from proved reserves, discounted at 10% per annum to present value, based on current economic and operating conditions, adjusted for related income tax effects.

Asset Retirement Obligation

The Company accounts for its future asset retirement obligations by recording the fair value of the liability during the period in which it was incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The increase in carrying value of a property associated with the capitalization of an asset retirement obligation is included in proven oil and gas properties in the balance sheets. The Company's asset retirement obligation consists of costs related to the plugging of wells, removal of facilities and equipment and site restoration on its oil and gas properties. The asset retirement liability is allocated to operating expense using a systematic and rational method. Asset retirement obligations amounted to $54,596 and $52,558 at September 30, 2011 and December 31, 2010, respectively.

Mineral Properties and Explorations Costs

The Company accounts for its mineral properties on a cost basis whereby all direct costs, net of pre-production revenue, relative to the acquisition of the properties are capitalized. All sales received are first credited against the costs of the related property, with any excess credited to earnings. Once commercial production has commenced, the net costs of the applicable property will be charged to operations using the unit-of-production method based on estimated proven and probable recoverable reserves. The net costs related to abandoned properties are charged to operations.

Exploration costs are charged to operations as incurred until such time that proven reserves are discovered. From that time forward, the Company will capitalize all costs to the extent that future cash flow from mineral reserves equals or exceeds the costs deferred. The deferred costs will be amortized over the recoverable reserves when a property reaches commercial production.

The Company reviews the carrying values of its mineral properties on a regular basis by reference to the project economics including the timing of the exploration and/or development work, the work programs and the exploration results experienced by the Company and others. The review of the carrying value of any producing property will be made by reference to the estimated future operating results and net cash flows. When the carrying value of a property exceeds its estimated net recoverable amount, provision is made for the decline in value.

The recoverability of the amounts recorded for mineral properties is dependent on the confirmation of economically recoverable reserves, confirmation of the Company’s interest in the underlying mineral claims, the ability of the Company to obtain the necessary financing to successfully complete their development and the attainment of future profitable operations or proceeds from disposition.

Estimated costs related to site restoration programs during the commercial development stage of the property are accrued over the life of the project.

Warrant Liability Derivative

The Company evaluates financial instruments for freestanding or embedded derivatives. As part of the July 2008 financing, the Company issued warrants that did not meet the specific conditions for equity classification. The Company is required to classify the fair value of the warrants issued as a liability, with subsequent changes in fair value recorded as income (loss). The fair value of the warrants will continue to be classified as a liability until the warrants are exercised, expire or are amended in a way that would no longer require classification as a liability.

Oil and Gas Revenues

The Company recognizes oil and gas revenues when oil and gas production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a purchaser's pipeline or truck. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations, distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 45 days following the month of production. Therefore, the Company may make accruals for revenues and accounts receivable based on estimates of its share of production. Since the settlement process may take 30 to 60 days following the month of actual production, its financial results may include estimates of production and revenues for the related time period. The Company will record any differences between the actual amounts ultimately received and the original estimates in the period they become finalized.

Foreign Currency Translation

For operations outside of the U.S. that prepare financial statements in currencies other than U.S. dollars, the Company translates the financial statements into U.S. dollars. Results of operations and cash flows are translated at average exchange rates during the period, and assets and liabilities are translated at end of period exchange rates, except for equity transactions and advances not expected to be repaid in the foreseeable future, which are translated at historical costs. The effects of exchange rate fluctuations on translating foreign currency assets and liabilities into U.S. dollars are accumulated as a separate component in other comprehensive income (loss).

Comprehensive income

The Company displays comprehensive income (loss) and its components as part of the consolidated statements of stockholders' equity. Comprehensive income (loss) is as follows for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income (loss) for the period	$ 1,169,217	$ 995,813	$ 3,792,151	$ 851,463
Foreign currency translation adjustments	(30,572)	-	(38,582)	-
Total comprehensive income (loss)	$ 1,138,645	$ 995,813	$ 3,753,569	$ 851,463

Accumulated other comprehensive income consists entirely of foreign currency translation adjustments at September 30, 2011 and December 31, 2010.

Earnings (Loss) Per Share

The computation of basic net income (loss) per common share is based on the weighted average number of shares that were outstanding during the year. The computation of diluted net income (loss) per common share is based on the weighted average number of shares used in the basic net income (loss) per share calculation plus the number of common shares that would be issued assuming the exercise of all potentially dilutive common shares outstanding using the treasury stock method for shares subject to stock options and warrants. See “Note 3. Earnings (Loss) Per Share” for further discussion.

Related Party Transactions

A related party is generally defined as (i) any person who holds 10% or more of the Company's securities and their immediate families, (ii) the Company's management, (iii) someone who directly or indirectly controls, is controlled by or is under common control with the Company, or (iv) anyone who can significantly influence the financial and operating decisions of the Company. A transaction is considered to be a related party transaction when there is a transfer of resources or obligations between related parties. See "Note 9. Related Party Transactions" for further discussion.

Concentration of Risk

Financial instruments that subject the Company to concentrations of credit risk consist primarily of cash and cash equivalents, and accounts receivable. The Company occasionally has cash deposits in excess of federally insured limits. The Company has not experienced any losses related to these balances, and management believes its credit risk to be minimal. Accounts receivable are with the operators of the oil wells in which the Company participates. Given the close working relationship between the operators and the Company, management believes its credit risk is minimal.

Fair Values of Financial Instruments

The Company measures certain financial assets and liabilities at fair value based on the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in on orderly transaction between market participants. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term nature of maturity of the instruments. See Note 6 for further discussion on fair value of financial instruments.

Recent and Adopted Accounting Pronouncements

From time to time, new accounting guidance is issued by FASB that the Company adopts as of the specified effective date. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on our financial statements upon adoption.

In June 2011, the FASB updated its guidance to make the presentation of comprehensive income more prominent in financial statements. The updated guidance requires companies to present net income, items of other comprehensive income and total comprehensive income in one continuous statement or two separate but consecutive statements. Presentation in the statement of stockholders' equity will no longer be permitted. These updates will become effective for the Company for interim and annual periods beginning in 2012, with early adoption permitted. The Company is still in the process of evaluating the manner in which it will implement this guidance.

Note 3. Earnings (Loss) Per Share (EPS)

There were no adjustments to net income in calculating diluted net income per share. The table below reconciles basic weighted shares outstanding to diluted weighted average shares outstanding:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Basic weighted average shares outstanding	63,075,122	63,075,122	63,075,122	63,075,122

Effect of dilutive securities - warrants	1,426,251	-	1,390,681	-
Diluted weighted average shares outstanding	64,501,373	63,075,122	64,465,803	63,075,122

Note 4. Oil and Gas Properties

The aggregate amount of capitalized costs relating to crude oil and natural gas producing activities and the aggregate amount of related accumulated depreciation, depletion and amortization at September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010	Change ($)
Proven properties	$ 433,522	$ 432,089	$ 1,433
Unproven properties	97,838	103,087	(5,249)
	531,360	535,176	(3,816)
Impairment and depletion, depreciation and amortization	(511,517)	(508,583)	(2,934)
Oil and gas properties, net	$ 19,843	$ 26,593	$ (6,750)

The Company amortizes all capitalized costs of oil and gas properties on the unit-of-production method using proved reserves, if available. The Company has not obtained reserve studies with estimated proved reserves. Management is assessing production data to determine the feasibility of obtaining reserves studies. Therefore at September 30, 2011 and December 31, 2010 there were no capitalized costs subject to amortization.

Unproven properties costs as of September 30, 2011 and December 31, 2010 are associated with a development oil well which was completed in August 2009 and did not produce. Management has impaired the well to the extent of anticipated salvage value of the equipment. During January 2011, the operator of this well presented a two-phase drilling plan to the working interest owners that required a significant investment. Management determined to not participate in the plan due to the required capital investment and the risk of a dry well. According to the Joint Operating Agreement the Company is subject to non-consent penalties that include a relinquishment of its interest in production from the well in favor of the participating working interest owners until the participating working interest owners have recovered 400% of the costs which would have been borne by the Company if it had elected to participate. During the three months ended September 30, 2011, the operator removed equipment from this well for use in another property in which we do not have a working interesting. Our proportionate share of the equipment removed was $7,390 which was greater than our net book value of $5,249. The difference of $2,141 was recognized as a gain on disposal of assets in the Consolidated Statement of Operations.

Properties which are not being amortized are assessed quarterly, on a property-by-property basis, to determine whether they are recorded at the lower of cost or fair market value. As a result of this analysis and lack of reserve studies, the Company recorded an impairment loss of $2,934 and $19,621 for the nine month periods ended September 30, 2011 and 2010, respectively. The impairment is similar to amortization and therefore is not added to the cost of properties being amortized.

Asset Retirement Obligation

The following table summarizes the activity for the Company’s asset retirement obligations:

	September 30, 2011	December 31, 2010
Asset retirement obligations, beginning of period	$ 52,558	$ 50,000
Accretion expense	2,038	2,558
Asset retirement obligations, end of period	54,596	52,558
Less: current portion	-	-
Long-term asset retirement obligations, end of period	$ 54,596	$ 52,558

Note 5. Mineral Properties and Exploration Expenses

Foster Township, Sudbury Ontario, Canada – Fostung Tungsten Property

On June 8, 2011, pursuant to an asset purchase agreement, the Company paid CAD $500,000 in cash for the acquisition of EMC Metals Corp's. 100% leasehold interest in two mining leases known as the Fostung tungsten property. The Fostung tungsten property consists of two contiguous claim blocks of 30 claims totaling 485 hectors. The nine claims covered by Mining Lease 108592 ("Lease One") expire on October 31, 2031. The twenty one claims covered by Mining Lease 105604 ("Lease Two") which originally expired on March 31, 2011 are in the process of being renewed and extended three years to 2014 by the Ministry of Northern Development, Mines and Forestry ("MNDMF"). The Company has performed the necessary assessment work and applied to the MNDMF to extend the expiry of Lease Two to October 2032. The Fostung property is located in Foster Township, Sudbury

Mining Division, Ontario, Canada. It is approximately 8 kilometers southeast of the town of Espanola and 70 kilometers west-southwest of the town of Sudbury. An excellent all-weather gravel road extends from Espanola, crossing the property and providing access to the west bay of Lake Panache.

A production bonus in the amount of CAD $500,000 is payable to Breakwater Resources Ltd. by the Company within thirty business days following the commencement of commercial production from the property. A 1% net smelter return royalty on the property is also payable to Breakwater Resources Ltd. by the Company. No capitalized costs have been amortized as of September 30, 2011. The Company did not incur any impairment of these capitalized costs through September 30, 2011.

Note 6. Fair Value Measurement

Fair value is defined within the accounting rules as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The rules established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1:	Valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority;

Level 2: Valuations rely on quoted prices in markets that are not active or observable inputs over the full term of the asset or liability;

Level 3: Valuations are based on prices or third party or internal valuation models that require inputs that are significant to the fair value measurement and are less observable and thus have the lowest priority.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis in the Company's Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Warrant Liability. Warrant liability derivatives are valued at each quarter-end using the Black-Scholes option pricing model and are affected by changes in inputs to that model including the Company's stock price, expected stock price volatility, the contractual term, and the risk-free interest rate. These unobservable inputs reflect the Company's own assumptions that market participants would use in pricing the liability. Given the unobservable nature of the inputs, the measurement of fair value is deemed to use Level 3 inputs. The changes in value are recognized as other income (expense) in the statements of operations. A reconciliation of the beginning and ending balances and changes in the warrant liability is included in Note 7.

The following table presents the Company's financial liabilities, which were accounted for at fair value on a recurring basis as of September 30, 2011, by level within the fair value hierarchy.

	September 30, 2011			
	Level 1	Level 2	Level 3	Total
LIABILITIES				
Warrant liability	$-	$-	$888,941	$888,941

The following table presents the Company's financial liabilities, which were accounted for at fair value on a recurring basis as of December 31, 2010, by level within the fair value hierarchy:

	December 31, 2010			
	Level 1	Level 2	Level 3	Total
LIABILITIES				
Warrant liability	$-	$-	$5,248,041	$5,248,041

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company's Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Oil and Gas Properties. Oil and gas properties which are not being amortized are assessed quarterly, on a property-by-property basis, to determine whether they are recorded at the lower of cost or fair market value. In determining whether such costs should be impaired, the Company evaluates historical experience, current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. Given the unobservable nature of the inputs, the measurement of fair value is deemed to use Level 3 inputs. The impairment is included in operating costs. See Note 4 for a summary of changes in capitalized costs of oil and gas properties.

Asset Retirement Obligation. The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, “Asset Retirement and Environmental Obligations.” The income valuation technique is utilized by the Company to determine the fair value of the liability at the point of inception by taking into account 1) the cost of abandoning oil and gas wells, which is based on the Company’s historical experience for similar work, or estimates from independent third-parties; 2) the economic lives of its properties, which is based on estimates by management; 3) the inflation rate; and 4) the credit adjusted risk-free rate, which takes into account the Company’s credit risk and the time value of money. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 4 for a summary of changes in the Company’s ARO liability.

The following table presents the Company’s financial assets and liabilities, which were accounted for at fair value on a non-recurring basis as of September 30, 2011, by level within the fair value hierarchy.

	September 30, 2011			
	Level 1	Level 2	Level 3	Total
ASSETS				
Oil and gas properties, net	$-	$-	$19,843	$19,843
LIABILITIES				
Asset retirement obligation	$-	$-	$54,596	$54,596

The following table presents the Company's financial assets and liabilities, which were accounted for at fair value on a non-recurring basis as of December 31, 2010, by level within the fair value hierarchy.

	December 31, 2010			
	Level 1	Level 2	Level 3	Total
ASSETS				
Oil and gas properties, net	$-	$-	$26,593	$26,593
LIABILITIES				
Asset retirement obligation	$-	$-	$52,558	$52,558

Note 7. Stockholders' Equity

On July 28, 2008, the Company completed a self-directed private placement of 6,450,000 units at a price of $0.50 per unit or $3,225,000 in the aggregate. Each unit consists of one share of the Company's common stock, one Series A stock purchase warrant ("Series A warrant") to purchase one share of common stock at $0.60 per share for a period of 18 months from the date of issuance and one Series B stock purchase warrant ("Series B warrant") to purchase one share of common stock at $0.75 per share for a period of 24 months from the date of issuance (refer to the "Warrants" section below for a discussion of the extension of the expiration date of the warrants).

In the event that during the period when the warrants are outstanding, if the Company issues common stock or common stock equivalents at a price per share which is less than the warrant exercise price, $0.60 per share for Series A warrants and $0.75 per share for Series B warrants, then the exercise price for the warrants shall be reduced to equal the share price of the new issuance and the number of warrant shares issuable shall be increased such that the aggregate exercise price payable shall be equal to the aggregate exercise price prior to such adjustment according to the Securities Purchase Agreement (the "Dilutive Issuance").

Warrants

Each of the Company's warrants outstanding entitles the holder to purchase one share of the Company's common stock for each warrant share held. No warrants were exercised during the nine month periods ended September 30, 2011 and September 30, 2010.

On August 27, 2010, the Company extended the expiration date of the 6,450,000 Series A warrants and the 6,450,000 Series B warrants to December 31, 2011. The exercise price of the warrants was not changed.

The potential of a Dilutive Issuance to the warrants' exercise price and number of underlying shares of common stock may result in a settlement amount that does not equal the difference between the fair value of a fixed number of the Company's common stock and a fixed exercise price. Accordingly, the warrants are not considered indexed to the Company's stock and, therefore, are accounted for as a derivative pursuant to ASC 815-40 Contracts in an Entity's Own Equity which became effective January 1, 2009. Upon the adoption of this guidance, the Company recognized a one-time decrease to opening accumulated deficit of $1,624,513.

As of September 30, 2011, the Company has not sold any shares of common stock or common stock equivalents that would result in an adjustment to the exercise price or number of shares of common stock underlying the warrants outstanding. Additionally, the Company does not intend to sell any shares of common stock or common stock equivalents at a price that is below the exercise price of the warrants, prior to their expiration dates, which would result in a Dilutive Issuance. Since the Company determined that the future probability of a Dilutive Issuance is deemed unlikely, it did not have a material impact on the fair value estimate of the warrant liability at September 30, 2011 as it relates to the Series A or Series B Warrants.

At September 30, 2011, the Company valued the warrant liability using a Black-Scholes model (Level 3 inputs) containing the following assumptions:

		Series A Warrants			Series B Warrants	
Warrants outstanding and exercisable at September 30, 2011		6,450,000			6,450,000	
Exercise price	$	0.60		$	0.75	
Black-Scholes option pricing model assumptions:						
Risk-free interest rate		0.200	%		0.200	%
Expected term (in years)		0.25			0.25	
Expected volatility		10.43	%		10.43	%
Dividend per share	$	0		$	0	
Expiration date		December 31, 2011			December 31, 2011	

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The following table is a roll forward of the fair value of the warrant liability related to the common stock warrants using the Black-Scholes assumptions as of September 30, 2011 (Level 3 inputs):

	Series A Warrants	Series B Warrants	Total
Balance, December 31, 2010	$ 2,744,200	$ 2,503,841	$ 5,248,041
Change in fair value	58,652	(64,488)	(5,836)
Balance, March 31, 2011	2,802,852	2,439,353	5,242,205
Change in fair value	(1,367,682)	(1,627,130)	(2,994,812)
Balance, June 30, 2011	1,435,170	812,223	2,247,393
Change in fair value	(594,732)	(763,720)	(1,358,452)
Balance, September 30, 2011	$ 840,438	$ 48,503	$ 888,941

As a result of adjusting the warrant liability to fair value, the Company recorded a non-cash gain of $594,732 and $763,720 relating to the Series A and Series B Warrants, respectively, for the three month period ended September 30, 2011.

Note 8. Commitments and Contingencies

As part of the acquisition of the Fostung tungsten property, located in Foster Township, Sudbury Mining Division, Ontario, Canada, the Company will pay to Breakwater Resources Ltd. (i) a Production Bonus in the amount of CAD $500,000 within thirty (30) business days following the commencement of commercial production from the property and (ii) a 1% Net Smelter Return royalty.

Note 9. Related Party Transactions

Legal Fees

Legal fees expensed for the three and nine month periods ended September 30, 2011, totaled $8,489 (2010: $12,358) and $42,504 (2010: $22,793), respectively, were paid or are due to the Company’s attorney, Mr. Sierchio, who was appointed to the board effective August 26, 2010.

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

Forward-Looking Statements

Except for the historical information presented in this document, the matters discussed in this Form 10-Q for the three-months ended September 30, 2011, and specifically in the items entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations," or otherwise incorporated by reference into this document, contain "forward-looking statements" (as such term is defined in the Private Securities Litigation Reform Act of 1995). These statements are identified by the use of forward-looking terminology such as "believes," "plans," "intend," "scheduled," "potential," "continue," "estimates," "hopes," "goal," "objective," expects," "may," "will," "should," or "anticipates" or the negative thereof or other variations thereon or comparable terminology, or by discussions of strategy that involve risks and uncertainties.

The safe harbor provisions of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended, apply to forward-looking statements made by the Company. The reader is cautioned that no statements contained in this Form 10-Q should be construed as a guarantee or assurance of future performance or results. These forward-looking statements involve risks and uncertainties, including those identified within this Form 10-Q. The actual results that the Company achieves may differ materially from any forward-looking statements due to such risks and uncertainties. These forward-looking statements are based on current expectations, and the Company assumes no obligation to update this information. Readers are urged to carefully review and consider the various disclosures made by the Company in this Form 10-Q and in the Company's other reports filed with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect the Company's business.

Overview

Incorporated under the laws of the State of Nevada, we have an authorized capital of 200,000,000 shares of $0.00001 par value common stock, of which 63,075,122 shares are outstanding and 10,000,000 shares of $0.0001 par value preferred stock, of which none are outstanding as of September 30, 2011.

Our principal executive offices are located at 430 Park Avenue, Suite 702, New York, NY, 10022. Our telephone number is 800-755-5815.

Description of Business

Janus Resources, Inc. (formerly Entheos Technologies, Inc.) (the “Company”, “we”, “us”, and “our”) is in the business o location, acquisition, exploration and, if warranted, development of both mineral exploration properties and oil and gas properties. The Company pursues oil and gas prospects in partnership with oil and gas companies with exploration, development and production expertise. Currently, its interests consist of non-operating, minority working interests in oil and gas properties. On June 8, 2011, the Company completed the acquisition of the Fostung tungsten property, located in Foster Township, Sudbury, Ontario, Canada.

We currently have interests in producing properties in La Salle County, Fayette County, Lee County and Frio County, Texas. The leases for these properties are maintained and operated by our partners Leexus Oil LLC and Millennium Petro Physics who recently took over for Bayshore Exploration LLC; there are no obligations to further explore or develop lands in the lease areas to maintain the leases. The operators of the leases are not affiliated with the Company or any of its directors or major shareholders. We are not aware of any relationships or affiliations between or among any of our leasehold partners and the lease operators.

On June 14, 2011, we completed the acquisition of the Fostung tungsten property, located in Foster Township, Sudbury, Ontario, Canada, from EMC Metals Corp. The sale price was CAD $500,000 cash, for 100% of the property rights.

The Fostung tungsten property was originally discovered and staked by local prospectors in 1966. Union Carbide Corporation ("UCC") optioned the claims in 1978 and pursued a large tonnage, lower grade skarn deposit with an exploration program that represents most of the money and work that has been expended throughout the property's history. Breakwater Resources Ltd. ("Breakwater") of Toronto, Canada optioned the property from UCC in 1988, and subsequently sold the property to EMC Metals Corp. (Golden Predator Corp.), in 2007. An independent National Instrument 43-101 technical report and resource estimate on the property was prepared in November of 2007 by SRK Consulting, of Lakewood, Colorado. That initial resource report presented an inferred resource estimate of 12.4 million tonnes, grading 0.213% WO 3, with a cut-off grade of 0.125%. SRK based this estimate on data from a total of 43 diamond core drill holes and an aggregate of 9,185 meters of drill results.

The property was subject to a production bonus payable to Breakwater, which was renegotiated from a common share payment to a straight cash payment of CAD $500,000, and which was assumed by the Company. A 1% net smelter return royalty on the property, also payable to Breakwater, was also assumed by the Company.

Oil and Gas Properties

The following table sets forth a summary of our current oil and gas interests:

	Acquisition Date	Interest Working		Net Revenue		Month Production Started	Acreage	Formation
Proven Properties:								
Cooke #6	9/1/2008	21.75	%	16.3125	%	Dec-07	40	Escondido
Onnie Ray #1	9/12/2008	20.00	%	15.00	%	Oct-08	80	Austin Chalk
Stahl #1	9/12/2008	20.00	%	15.00	%	Oct-08	20	Austin Chalk
Pearce #1	10/31/2008	20.00	%	15.00	%	Dec-08	360	Austin Chalk
Unproven Properties:								
Haile #1	9/12/2008	20.00	%	15.00	%	-	100	Austin Chalk

We utilize the full cost method of accounting for our oil and gas activities. In accordance with the full cost method of accounting, all costs associated with acquisition, exploration, and development of oil and gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized. Net capitalized costs associated with oil and gas properties as of September 30, 2011 and December 31, 2010 are summarized as follows:

	September 30, 2011	December 31, 2010	Change ($)
Proven properties	$ 433,522	$ 432,089	$ 1,433
Unproven properties	97,838	103,087	(5,249)
	531,360	535,176	(3,816)
Impairment and depletion, depreciation and amortization	(511,517)	(508,583)	(2,934)
Oil and gas properties, net	$ 19,843	$ 26,593	$ (6,750)

The unproven property is a well completed in August 2009 which did not produce. Management has impaired the well to the extent of the anticipated salvage value of the equipment. During January 2011, the operator of this well presented a two-phase drilling plan to the working interest owners that required a significant investment. Management determined to not participate in the plan due to the required capital investment and the risk of a dry well. According to the Joint Operating Agreement the Company is subject to non-consent penalties that include a relinquishment of its interest in production from the well in favor of the participating working interest owners until the participating working interest owners have recovered 400% of the costs which would have been borne by the Company if it had elected to participate. During the three months ended September 30, 2011, the operator removed equipment from this well for use in another property in which we do not have a working interesting. Our proportionate share of the equipment removed was $7,390 which was greater than our net book value of $5,249. The difference of $2,141 was recognized as a gain on disposal of assets in the Consolidated Statement of Operations.

Critical Accounting Policies

Full Cost Method of Accounting for Oil and Gas Properties

The Company has elected to utilize the full cost method of accounting for its oil and gas activities. In accordance with the full cost method of accounting, all costs associated with acquisition, exploration, and development of oil and gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized.

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves once proved reserves are determined to exist. The Company has not yet obtained reserve reports. Management is assessing production data to determine the feasibility of obtaining reserves studies. At September 30, 2011, there were no capitalized costs subject to amortization.

Oil and gas properties without estimated proved reserves are not amortized until proved reserves associated with the properties can be determined or until impairment occurs. As a result of management's impairment analysis, the Company recorded an impairment loss of $2,934 and $19,621 during the nine month periods ended September 30, 2011 and 2010, respectively. The impairment is similar to amortization and therefore is not added to the costs of properties being amortized. See "Note 6. Fair Value Measurement" for further information.

Sales of oil and gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income. The Company has not sold any oil and gas properties.

Full Cost Ceiling Test

At the end of each quarterly reporting period, the unamortized costs of oil and gas properties are subject to a “ceiling test” which basically limits capitalized costs to the sum of the estimated future net revenues from proved reserves, discounted at 10% per annum to present value, based on current economic and operating conditions, adjusted for related income tax effects.

Asset Retirement Obligation

The Company accounts for its future asset retirement obligations by recording the fair value of the liability during the period in which it was incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The increase in carrying value of a property associated with the capitalization of an asset retirement obligation is included in proven oil and gas properties in the balance sheets. The Company’s asset retirement obligation consists of costs related to the plugging of wells, removal of facilities and equipment and site restoration on its oil and gas properties. The asset retirement liability is allocated to operating expense using a systematic and rational method. Asset retirement obligations amounted to $54,596 and $52,558 at September 30, 2011 and December 31, 2010, respectively.

Mineral Properties and Explorations Costs

The Company accounts for its mineral properties on a cost basis whereby all direct costs, net of pre-production revenue, relative to the acquisition of the properties are capitalized. All sales received are first credited against the costs of the related property, with any excess credited to earnings. Once commercial production has commenced, the net costs of the applicable property will be charged to operations using the unit-of-production method based on estimated proven and probable recoverable reserves. The net costs related to abandoned properties are charged to operations.

Exploration costs are charged to operations as incurred until such time that proven reserves are discovered. From that time forward, the Company will capitalize all costs to the extent that future cash flow from mineral reserves equals or exceeds the costs deferred. The deferred costs will be amortized over the recoverable reserves when a property reaches commercial production.

The Company reviews the carrying values of its mineral properties on a regular basis by reference to the project economics including the timing of the exploration and/or development work, the work programs and the exploration results experienced by the Company and others. The review of the carrying value of any producing property will be made by reference to the estimated future operating results and net cash flows. When the carrying value of a property exceeds its estimated net recoverable amount, provision is made for the decline in value.

The recoverability of the amounts recorded for mineral properties is dependent on the confirmation of economically recoverable reserves, confirmation of the Company’s interest in the underlying mineral claims, the ability of the Company to obtain the necessary financing to successfully complete their development and the attainment of future profitable operations or proceeds from disposition.

Estimated costs related to site restoration programs during the commercial development stage of the property are accrued over the life of the project.

Warrant Liability Derivative

The Company evaluates financial instruments for freestanding or embedded derivatives. As part of the July 2008 financing, the Company issued warrants that did not meet the specific conditions for equity classification. The Company is required to classify the fair value of the warrants issued as a liability, with subsequent changes in fair value recorded as income (loss). The fair value of the warrants will continue to be classified as a liability until the warrants are exercised, expire or are amended in a way that would no longer require classification as a liability.

Oil and Gas Revenues

The Company recognizes oil and gas revenues when oil and gas production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a purchaser's pipeline or truck. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations, distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 45 days following the month of production. Therefore, the Company may make accruals for revenues and accounts receivable based on estimates of its share of production. Since the settlement process may take 30 to 60 days following the month of actual production, its financial results may include estimates of production and revenues for the related time period. The Company will record any differences between the actual amounts ultimately received and the original estimates in the period they become finalized.

Variables and Trends

We have very limited history with respect to our acquisition and development of oil and gas properties. In the event we are able to obtain the necessary financing to move forward with our growth plans, we expect our expenses to increase significantly as we grow our business. Accordingly, the comparison of the financial data for the periods presented may not be a meaningful indicator of our future performance and must be considered in light of these circumstances.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following is a description of the meanings of some of the natural gas and oil industry terms used in this filing:

"Bbl" means a barrel or barrels of oil.

"BOE" means barrels of oil equivalent.

"Btu" means British thermal unit, which means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

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

"Condensate" means hydrocarbons naturally occurring in the gaseous phase in a reservoir that condense to become a liquid at the surface due to the change in pressure and temperature.

"Crude" means unrefined liquid petroleum.

"Gross acres" or "gross wells" refer to the total acres or wells, as the case may be, in which a working interest is owned.

"Mcf" means thousand cubic feet of natural gas. The Company has assumed that 1Mcf = 1 MMBtu for our calculations.

"MMBtu" means one million Btus.

"Operator" refers to the individual or company responsible for the exploration, development and production of an oil or gas well or lease.

"Proved developed oil and gas reserves" refers to reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production responses that increased recovery will be achieved.

"Proved oil and gas reserves" means the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. Estimates of proved reserves do not include the following: (a) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (b) crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors; (c) crude oil, natural gas and natural gas liquids that may occur in undrilled prospects; and (d) crude oil, natural gas and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

“Proven properties” refers to properties containing proved reserves.

“Proved undeveloped reserves” refers to reserves 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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves may not include estimates attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

“Recompletion” means, after the initial completion of the well, the actions and techniques of re-entering the well and redoing or repairing the original completion in order to restore the well's productivity.

“Shut-in” means a well which is capable of producing but is not presently producing.

“Unproven properties” refers to properties containing no proved reserves.

“Working interest” refers to the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

“Workover” means operations on a producing well to restore or increase production.

GLOSSARY OF CERTAIN MINERAL EXPLORATION TERMS

The following is a description of the meanings of some mineral exploration terms used in this filing:

"Net Smelter Return ("NSR") royalties are based on the value of production or net proceeds received by the operator from a smelter or refinery. These proceeds are usually subject to deductions or charges for transportation, insurance, smelting and refining costs as set out in the royalty agreement. For gold royalties, the deductions are generally minimal while for base metal projects, the deductions can be much more substantial. This type of royalty provides cash flow that is free of any operating or capital costs and environmental liabilities. A smaller percentage NSR in a project can effectively equate to the economic value of a larger percentage profit or working interest in the same project.

Results of Operations

The following table sets forth certain unaudited operating information with respect to the Company's operations for the periods indicated:

	Three Months Ended September 30, 2011	2010	change	% change
Production:				
Oil (Bbls)	39.4	54.4	(15.0)	(28)%
Gas (Mcf)	210.7	339.7	(129.0)	(38)%
Total production (BOE)	74.5	111.0	(36.5)	(33)%
Average daily production (BOE)	0.8	1.2	(0.4)	(33)%
% oil of production	53%	49%	4%	8%
Average sales price:				
Oil (per Bbl)	$81.94	$67.66	$14.28	21%
Gas (per Mcf)	$10.39	$7.27	$3.12	43%
Total production (per BOE)	$81.79	$55.41	$26.38	48%
Oil and gas revenues:				

Oil revenue	$3,816	$3,679	$137	4 %				
Gas revenue	$2,279	$2,471	$(192)	(8)%				
Total	$6,095	$6,150	$(55)	(1)%				
Lease operating expenses	$5,319	$4,247	$1,072	25 %				
Additional per BOE data:								
Sales price	$81.79	$55.41	$26.38	48 %				
Lease operating expenses	$71.38	- $	-	194,050				
Dividends ($.08 per share)	-	-	-	-	(1,347,608)	-	-	(1,347,6
Distribution of restricted stock to officers and directors	-	-	(735,965)	-	-	44,065	736,699	734
Increase in deferred directors' compensation charged to expense	-	-	-	108,384	-	-	-	108,384
Balances at December 31, 2017 (unaudited)	16,863,004	$280,938	$2,186,538	$3,568,293	$125,767,547	(154,044)	$(2,620,643)	$129,182

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.

CONDENSED STATEMENTS OF CASH FLOWS

	Three months ended December 31,	
	2018	2017
Operating Activities	(unaudited)	
Net income (loss)	$12,735,940	$13,784,939
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	3,813,686	5,275,824
Provision for deferred income taxes	4,314,000	(12,738,000)
Gain from leasing fee mineral acreage	(514,557)	(96,843)
Proceeds from leasing fee mineral acreage	528,374	98,692
Net (gain) loss on sales of assets	(9,096,938)	272,236
Directors' deferred compensation expense	80,287	108,384
Fair value of derivative contracts	(6,206,181)	851,036
Restricted stock awards	159,469	194,050
Other	7,163	(3,237)
Cash provided (used) by changes in assets and liabilities:		
Oil, NGL and natural gas sales receivables	(77,414)	229,701
Other current assets	(261,308)	(59,253)
Accounts payable	(2,971)	(86,404)
Income taxes receivable	(754,153)	24,574
Other non-current assets	28,899	(79,552)
Accrued liabilities	(744,553)	(577,564)
Total adjustments	(8,726,197)	(6,586,356)
Net cash provided by operating activities	4,009,743	7,198,583
Investing Activities		
Capital expenditures	(1,445,939)	(4,984,880)
Acquisition of minerals and overrides	(423,000)	-
Investments in partnerships	-	5,393
Proceeds from sales of assets	9,096,938	557,750
Net cash provided (used) by investing activities	7,227,999	(4,421,737)
Financing Activities		
Borrowings under debt agreement	3,832,557	8,272,575
Payments of loan principal	(13,332,557)	(10,094,795)
Purchases of treasury stock	(1,140,559)	(272,100)
Payments of dividends	(673,892)	(671,890)
Net cash provided (used) by financing activities	(11,314,451)	(2,766,210)
Increase (decrease) in cash and cash equivalents	(76,709)	10,636
Cash and cash equivalents at beginning of period	532,502	557,791
Cash and cash equivalents at end of period	$455,793	$568,427

Supplemental Schedule of Noncash Investing and Financing Activities:		
Dividends declared and unpaid	$673,897	$675,718
Additions to asset retirement obligations	$5,371	$12,026
Gross additions to properties and equipment	$1,894,741	$4,287,096
Net (increase) decrease in accounts payable for properties and equipment additions	(25,802)	697,784
Capital expenditures and acquisitions	$1,868,939	$4,984,880

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.

NOTES TO CONDENSED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1: Basis of Presentation and Accounting Principles

Basis of Presentation

The accompanying unaudited condensed financial statements of Panhandle Oil and Gas Inc. have been prepared in accordance with the instructions to Form 10-Q as prescribed by the SEC. Management of the Company believes that all adjustments necessary for a fair presentation of the financial position and results of operations and cash flows for the periods have been included. All such adjustments are of a normal recurring nature. The results are not necessarily indicative of those to be expected for the full year. The Company’s fiscal year runs from October 1 through September 30.

Certain amounts and disclosures have been condensed or omitted from these financial statements pursuant to the rules and regulations of the SEC. Therefore, these condensed financial statements should be read in conjunction with the financial statements and related notes thereto included in the Company’s 2018 Annual Report on Form 10-K.

Certain amounts (loss (gain) on asset sales and other in the Statements of Operations) in the prior years have been reclassified to conform to the current year presentation.

Adoption of New Accounting Pronouncements

Revenue recognition and presentation – In May 2014, the FASB issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes nearly all previously existing revenue recognition guidance under U.S. GAAP. Subsequently, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This new guidance became effective for reporting periods beginning after December 15, 2017. The Company adopted the new revenue recognition and presentation guidance on October 1, 2018, as required. See Note 2: Revenues for discussion of the adoption impact and the applicable disclosures required by the new guidance.

New Accounting Pronouncements yet to be Adopted

In February 2016, the FASB issued its new lease accounting guidance in ASU 2016-02, Leases (Topic 842). Under the new guidance, lessees will be required to recognize the following for all leases (with the exception of short-term leases pursuant to an optional election) at the commencement date: 1) a lease liability, which is a lessee’s obligation to make lease payments arising from a lease, measured on a discounted basis; and 2) a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. The new lease guidance changed the accounting for sale and leaseback transactions primarily because lessees must recognize lease assets and lease liabilities. Lessees will no longer be provided with a source of off-balance sheet financing. The guidance is effective for us beginning October 1, 2019, including interim periods within the fiscal year. Early application is permitted for all public business entities upon issuance, but the Company has chosen not to early adopt. Lessees (for capital and operating leases) and lessors (for sales-type, direct financing, and operating leases) must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The modified retrospective approach would not require any transition accounting for leases that expired before the earliest comparative period presented. We are assessing the potential impact that this standard will have on our financial statements.

In January 2016, the FASB issued ASU 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. The new guidance is intended to improve the recognition and measurement of financial instruments. The new guidance is effective for us beginning October 1, 2018, including interim periods within the fiscal year. This update is not expected to have a material impact on our financial statements.

Other accounting standards that have been issued or proposed by the FASB, or other standards-setting bodies, that do not require adoption until a future date are not expected to have a material impact on the financial statements upon adoption.

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NOTE 2: Revenues

Adoption of new revenue recognition and disclosure guidance

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which generally requires an entity to identify performance obligations in its contracts, estimate the amount of consideration to be received in the transaction price, allocate the transaction price to each separate performance obligation, and recognize revenue as obligations are satisfied. Additionally, the standard requires expanded disclosures related to revenue recognition.

Subsequent to the issuance of ASU 2014-09, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), pertaining to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis. This guidance requires an entity to record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity shall record revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer.

The Company adopted the new revenue recognition and presentation guidance on October 1, 2018. The standard allows for either “full retrospective” adoption, meaning the standard is applied to all of the periods presented, or “modified retrospective” adoption, meaning the standard is applied only to the most current period presented in the financial statements and utilizes a cumulative effect adjustment to retained earnings in the period of adoption to account for prior period effects rather than restating previously reported results. The Company chose to use the modified retrospective method upon adoption and has applied the guidance only to contracts that are not complete at the date of initial application. Adoption of the new guidance had no cumulative effect impact on the Company's retained earnings at October 1, 2018.

The standard did not have a material effect on the timing or measurement of the Company's revenue recognition or its financial position, results of operations, net income and cash flows. Additionally, the application of ASU 2016-08’s gross versus net presentation guidance did not impact the Company’s presentation of revenues and expenses. As the Company’s interests in oil and natural gas properties are non-operated interests or royalty interests, the Company evaluated its agreements with operators in connection with the ASC 606 principal versus agent indicators. Consistent with previous conclusions under ASC 605, the Company concluded that the operators act as an agent in the transfer of commodities to third party customers. This determination required judgment in the application of the guidance for principal versus agent under ASC 606.

Revenues from Contracts with Customers

Oil, NGL and natural gas sales

Sales of oil, NGL and natural gas are recognized at the point in time that control of the product is transferred to the customer and collectability of the sales price is reasonably assured. Oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. The price the Company receives for natural gas and NGL is tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality and heat content of natural gas, and prevailing supply and demand conditions, so that the price of natural gas fluctuates to remain competitive with other available natural gas supplies. These market indices are determined on a monthly basis. Each unit of commodity is considered a separate performance obligation, however, as consideration is variable, the Company utilizes the variable consideration allocation exception permitted under the standard to allocate the variable consideration to the specific units of commodity to which they relate.

Lease bonus income

The Company also earns revenue from lease bonuses. The Company generates lease bonus revenue by leasing its mineral interests to exploration and production companies. A lease agreement represents the Company's contract with a third party and generally conveys the rights to any oil, NGL or natural gas discovered, grants the Company a right to a specified royalty interest and requires that drilling and completion operations commence within a specified time period. Control is transferred to the lessee and the Company has satisfied its performance obligation when the lease agreement is executed, such that revenue is recognized when the lease bonus payment is received. The Company accounts for its lease bonuses as conveyances in accordance with the guidance set forth in ASC 932, and it recognizes the lease bonus as a cost recovery with any excess above its cost basis in the mineral being treated as a gain. The excess of lease bonus above the mineral basis is shown in the lease bonuses and rentals line item on the Company's Statements of Operations.

Oil and natural gas derivative contracts – See Note 9 for discussion of the Company's accounting for derivative contracts.

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Disaggregation of oil, NGL and natural gas revenues

The following table presents the disaggregation of the Company's oil, NGL and natural gas revenues for the three months ended December 31, 2018.

	Three Months Ended December 31, 2018
Oil revenue	$ 4,478,980
NGL revenue	1,454,835
Natural gas revenue	6,276,904
Oil, NGL and natural gas sales	$ 12,210,719

Performance obligations

The Company satisfies the performance obligations under its oil and natural gas sales contracts upon delivery of its production and related transfer of title to purchasers. Upon delivery of production, the Company has a right to receive consideration from its purchasers in amounts that correspond with the value of the production transferred.

Allocation of transaction price to remaining performance obligations

Oil, NGL and natural gas sales

As the Company has determined that each unit of product generally represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. The Company has utilized the practical expedient in ASC 606 which permits the Company to allocate variable consideration to one or more but not all performance obligations in the contract if the terms of the variable payment relate specifically to the Company’s efforts to satisfy that performance obligation and allocating the variable amount to the performance obligation is consistent with the allocation objective under ASC 606. Additionally, the Company will not disclose variable consideration subject to this practical expedient.

Prior-period performance obligations and contract balances

The Company records revenue in the month production is delivered to the purchaser. As a non-operator, the Company has limited visibility into the timing of when new wells start producing and production statements may not be received for 30 to 90 days or more after the date production is delivered. As a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The expected sales volumes and prices for these properties are estimated and recorded within the Oil, NGL and natural gas sales receivables line item in the accompanying balance sheets. The difference between the Company's estimates and the actual amounts received for oil, NGL and natural gas sales is recorded in the quarter that payment is received from the third party. For the three months ended December 31, 2018, and December 31, 2017, revenue recognized in these reporting periods related to performance obligations satisfied in prior reporting periods was immaterial and considered a change in estimate.

NOTE 3: Income Taxes

The Company’s provision for income taxes differs from the statutory rate primarily due to estimated federal and state benefits generated from excess federal and Oklahoma percentage depletion, which are permanent tax benefits. Excess percentage depletion, both federal and Oklahoma, can only be taken in the amount that it exceeds cost depletion which is calculated on a unit-of-production basis. Excess tax benefits and deficiencies of stock-based compensation are recognized as income tax expense (benefit) in the statement of operations.

Both excess federal percentage depletion, which is limited to certain production volumes and by certain income levels, and excess Oklahoma percentage depletion, which has no limitation on production volume, reduce estimated taxable income or add to estimated taxable loss projected for any year. The federal and Oklahoma excess percentage depletion estimates will be updated throughout the year until finalized with detailed well-by-well calculations at fiscal year-end. Federal and Oklahoma excess percentage depletion, when a provision for income taxes is expected for the year, decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is expected for the year. The benefits of federal and Oklahoma excess percentage depletion and excess tax benefits and deficiencies of stock-based compensation are not directly related to the amount of pre-tax income (loss) recorded in a period. Accordingly, in periods where a recorded pre-tax income or loss is relatively small, the

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proportional effect of these items on the effective tax rate may be significant. The effective tax rate for the quarter ended December 31, 2018, was a 22% provision as compared to a 1182% benefit for the quarter ended December 31, 2017.

NOTE 4: Basic and Diluted Earnings (Loss) per Share

Basic and diluted earnings (loss) per share is calculated using net income (loss) divided by the weighted average number of voting common shares outstanding, including unissued, vested directors' deferred compensation shares during the period.

NOTE 5: Long-term Debt

The Company has a $200,000,000 credit facility with a group of banks headed by Bank of Oklahoma (BOK) with a current borrowing base of $80,000,000 and a maturity date of November 30, 2022. The credit facility is subject to a semi-annual borrowing base determination, wherein BOK applies their commodity pricing forecast to the Company's reserve forecast and determines a borrowing base. The facility is secured by certain of the Company's properties (wellbore only) with a net book value of $133,361,948 at December 31, 2018. The interest rate is based on BOK prime plus from 0.50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%. The election of BOK prime or LIBOR is at the Company's discretion. The interest rate spread from BOK prime or LIBOR will be charged based on the ratio of the loan balance to the borrowing base. The interest rate spread from LIBOR or the prime rate increases as the ratio of loan balance to the borrowing base increases. At December 31, 2018, the effective interest rate was 4.63%.

The Company's debt is recorded at the carrying amount on its balance sheet. The carrying amount of the Company's revolving credit facility approximates fair value because the interest rates are reflective of market rates.

Determinations of the borrowing base are made semi-annually (usually June and December) or whenever the banks, in their discretion, believe that there has been a material change in the value of the oil and natural gas properties. On January 3, 2019, the borrowing base was redetermined by the banks and left unchanged at $80,000,000. The loan agreement contains customary covenants which, among other things, require periodic financial and reserve reporting and place certain limits on the Company's incurrence of indebtedness, liens, payment of dividends and acquisitions of stock. In addition, the Company is required to maintain certain financial ratios, a current ratio (as defined by the bank agreement – current assets includes availability under outstanding credit facility) of no less than 1.0 to 1.0 and a funded debt to EBITDA (trailing twelve months as defined by the bank agreement – traditional EBITDA with the unrealized gain or loss on derivative contracts also removed from earnings) of no more than 4.0 to 1.0. At December 31, 2018, the Company was in compliance with the covenants of the loan agreement and has $38,500,000 of availability under its outstanding credit facility.

NOTE 6: Deferred Compensation Plan for Non-Employee Directors

Annually, non-employee directors may elect to be included in the Deferred Compensation Plan for Non-Employee Directors. The Deferred Compensation Plan for Non-Employee Directors provides that each outside director may individually elect to be credited with future unissued shares of Company common stock rather than cash for all or a portion of the annual retainers, Board meeting fees and committee meeting fees. These unissued shares are recorded to each director's deferred compensation account at the closing market price of the shares (i) on the dates of the Board and committee meetings, and (ii) on the payment dates of the annual retainers. Only upon a director's retirement, termination, death, or a change-in-control of the Company will the shares recorded for such director be issued under the Deferred Compensation Plan for Non-Employee Directors. Directors may elect to receive shares, when issued, over annual time periods up to ten years. The promise to issue such shares in the future is an unsecured obligation of the Company.

NOTE 7: Restricted Stock Plan

In March 2010, shareholders approved the Panhandle Oil and Gas Inc. 2010 Restricted Stock Plan (2010 Stock Plan), which made available 200,000 shares of common stock to provide a long-term component to the Company's total compensation package for its officers and to further align the interest of its officers with those of its shareholders. In March 2014, shareholders approved an amendment to increase the number of shares of common stock reserved for issuance under the 2010 Stock Plan from 200,000 shares to 500,000 shares and to allow the grant of shares of restricted stock to our directors. The 2010 Stock Plan, as amended, is designed to provide as much flexibility as possible for future grants of restricted stock so that the Company can respond as necessary to provide competitive compensation in order to attract, retain and motivate directors and officers of the Company and to align their interests with those of the Company's shareholders.

Effective in May 2014, the board of directors adopted resolutions to allow management, at their discretion, to purchase the Company's common stock as treasury shares up to an amount equal to the aggregate number of shares of common stock awarded pursuant to the Company's Amended 2010 Restricted Stock Plan, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors.

Effective in May 2018, the board of directors approved an amendment to the Company's existing stock repurchase program. As amended, the Repurchase Program will continue to allow the Company to repurchase up to $1.5 million of the Company's common stock at management's discretion. The Board added language to clarify that this is intended to be an evergreen program as the repurchase of an additional $1.5 million of the Company's common stock is authorized and approved whenever the previous amount is utilized. In addition, the number of shares allowed to be purchased by the Company under the Repurchase Program is no longer capped at an amount equal to the aggregate number of shares of common stock (i) awarded pursuant to the Company's Amended 2010 Restricted Stock Plan, (ii) contributed by the Company to its ESOP, and (iii) credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors.

On December 11, 2018, the Company awarded 12,044 non-performance based shares and 36,131 performance based shares of the Company's common stock as restricted stock to certain officers. The restricted stock vests at the end of a three-year period and contains non-forfeitable rights to receive dividends and voting rights during the vesting period. Upon vesting, the performance based shares that do not meet the performance criteria are forfeited. The non-performance and performance based shares had a fair value on their award date of $189,332 and $297,621, respectively. The fair value for the non-performance and the performance based awards will be recognized as compensation expense ratably over the vesting period. The fair value of the performance based shares on their award date is calculated by simulating the Company's stock prices as compared to the Dow Jones Select Oil Exploration and Production Index (DJSOEP) prices utilizing a Monte Carlo model covering the performance period (December 11, 2018, through December 11, 2021).

On December 31, 2018, the Company awarded 11,290 non-performance based shares of the Company's common stock as restricted stock to its non-employee directors. The restricted stock vests quarterly over one year starting on March 31, 2019. The restricted stock contains non-forfeitable rights to receive dividends and to vote the shares during the vesting period. These non-performance based shares had a fair value on their award date of $174,995.

The following table summarizes the Company's pre-tax compensation expense for the three months ended December 31, 2018 and 2017, related to the Company's performance based and non-performance based restricted stock.

	Three Months Ended December 31,	
	2018	2017
Performance based, restricted stock	$63,537	$96,665
Non-performance based, restricted stock	95,932	97,385
Total compensation expense	$159,469	$194,050

A summary of the Company's unrecognized compensation cost for its unvested performance based and non-performance based restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

	As of December 31, 2018	
	Unrecognized Compensation Cost	Weighted Average Period (in years)
Performance based, restricted stock	$ 555,473	2.29
Non-performance based, restricted stock	543,061	1.86
Total	$ 1,098,534	

NOTE 8: Properties and Equipment

Divestitures

During the first quarter of 2019, the Company sold 206 net mineral acres and producing oil and gas properties, primarily located in Lea and Eddy Counties, New Mexico, to a private buyer for total net consideration of $9,096,938 and recorded a gain on the sale of $9,096,938. The cash from the sale was used to reduce the Company's outstanding bank debt.

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Acquisitions

During the first quarter of 2019, the Company acquired 45 net mineral acres (which include producing oil and gas properties) in the STACK play in Blaine County, Oklahoma, with undeveloped locations identified in both the Woodford and Meramac Shales for $423,000.

Oil, NGL and Natural Gas Reserves

Management considers the estimation of the Company’s crude oil, NGL and natural gas reserves to be the most significant of its judgments and estimates. Changes in crude oil, NGL and natural gas reserve estimates affect the Company’s calculation of DD&A, provision for retirement of assets and assessment of the need for asset impairments. On an annual basis, with a semi-annual update, the Company’s Independent Consulting Petroleum Engineer, with assistance from Company staff, prepares estimates of crude oil, NGL and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geologic and geophysical information. Between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing appropriate prices for the current period. The estimated oil, NGL and natural gas reserves were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month oil, NGL and natural gas price for each month within the 12-month period prior to the balance sheet date, held flat over the life of the properties. However, projected future crude oil, NGL and natural gas pricing assumptions are used by management to prepare estimates of crude oil, NGL and natural gas reserves and future net cash flows used in asset impairment assessments and in formulating management’s overall operating decisions. Crude oil, NGL and natural gas prices are volatile and affected by worldwide production and consumption and are outside the control of management.

Impairment

All long-lived assets, principally oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its estimated future net cash flows. The evaluations involve significant judgment since the results are based on estimated future events, such as: inflation rates; future drilling and completion costs; future sales prices for oil, NGL and natural gas; future production costs; estimates of future oil, NGL and natural gas reserves to be recovered and the timing thereof; the economic and regulatory climates and other factors. The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil, NGL and natural gas reserves. Between periods in which reserves would normally be calculated, the Company updates the reserve calculations to reflect any material changes since the prior report was issued and then utilizes updated projected future price decks current with the period. For both the three months ended December 31, 2018 and 2017, the assessment resulted in no impairment provisions on producing properties. A significant reduction in oil, NGL and natural gas prices or a decline in reserve volumes may lead to additional impairment in future periods that may be material to the Company.

NOTE 9: Derivatives

The Company has entered into commodity price derivative agreements including fixed swap contracts and costless collar contracts. These instruments are intended to reduce the Company's exposure to short-term fluctuations in the price of oil and natural gas. Fixed swap contracts set a fixed price and provide payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price. Collar contracts set a fixed floor price and a fixed ceiling price and provide payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. These contracts cover only a portion of the Company's natural gas and oil production and provide only partial price protection against declines in natural gas and oil prices. These derivative instruments may expose the Company to risk of financial loss and limit the benefit of future increases in prices. The Company's derivative contracts are currently with Bank of Oklahoma and Koch Supply and Trading LP. The derivative contracts with Bank of Oklahoma are secured under its credit facility with Bank of Oklahoma. The derivative contracts with Koch are unsecured. The derivative instruments have settled or will settle based on the prices below.

Derivative contracts in place as of December 31, 2018

Contract period	Production volume covered per month	Index	Contract price
Natural gas fixed price swaps			
July 2018 - March 2019	50,000 Mmbtu	NYMEX Henry Hub	$3.065
January - March 2019	100,000 Mmbtu	NYMEX Henry Hub	$3.460
January - June 2019	150,000 Mmbtu	NYMEX Henry Hub	$2.981
January - June 2019	100,000 Mmbtu	NYMEX Henry Hub	$3.310
January - June 2019	50,000 Mmbtu	NYMEX Henry Hub	$3.303
January - July 2019	100,000 Mmbtu	NYMEX Henry Hub	$2.867
Oil costless collars			
January - June 2019	2,000 Bbls	NYMEX WTI	$55.00 floor / $63.45 ceiling
January - December 2019	1,000 Bbls	NYMEX WTI	$50.00 floor / $60.00 ceiling
January - December 2019	2,000 Bbls	NYMEX WTI	$60.00 floor / $69.25 ceiling
July - December 2019	3,000 Bbls	NYMEX WTI	$60.00 floor / $70.75 ceiling
July 2019- June 2020	2,000 Bbls	NYMEX WTI	$65.00 floor / $76.15 ceiling
January - June 2020	2,000 Bbls	NYMEX WTI	$60.00 floor / $67.00 ceiling
Oil fixed price swaps			
January - June 2019	2,000 Bbls	NYMEX WTI	$59.69
January - June 2019	2,000 Bbls	NYMEX WTI	$57.15
January - June 2019	3,000 Bbls	NYMEX WTI	$58.02
January - December 2019	1,000 Bbls	NYMEX WTI	$56.15
January - December 2019	2,000 Bbls	NYMEX WTI	$56.71
January - December 2019	1,000 Bbls	NYMEX WTI	$58.56
July - December 2019	2,000 Bbls	NYMEX WTI	$56.85

The Company has elected not to complete all of the documentation requirements necessary to permit these derivative contracts to be accounted for as cash flow hedges. The Company's fair value of derivative contracts was a net asset of $2,792,165 as of December 31, 2018, and a net liability of $3,414,016 as of September 30, 2018. Net cash paid related to derivative contracts settled during the three-month period ended December 31, 2018, was $1,699,401 compared to net cash received of $357,184 in the same period in the prior year.

The fair value amounts recognized for the Company’s derivative contracts executed with the same counterparty under a master netting arrangement may be offset. The Company has the choice to offset or not, but that choice must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for the derivative contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Balance Sheets.

The following table summarizes and reconciles the Company's derivative contracts’ fair values at a gross level back to net fair value presentation on the Company's Condensed Balance Sheets at December 31, 2018, and September 30, 2018. The Company

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has offset all amounts subject to master netting agreements in the Company's Condensed Balance Sheets at December 31, 2018, and September 30, 2018.

	December 31, 2018 Fair Value (a) Commodity Contracts			September 30, 2018 Fair Value (a) Commodity Contracts		
	Current Assets	Current Liabilities	Non-Current Assets	Current Assets	Current Liabilities	Non-Current Liabilities
Gross amounts recognized	$2,502,245	$32,617	$ 322,537	$42,150	$3,106,196	$ 349,970
Offsetting adjustments	(32,617)	(32,617)	-	(42,150)	(42,150)	-
Net presentation on Condensed Balance Sheets	$2,469,628	$ -	$ 322,537	$-	$3,064,046	$ 349,970

(a) See Fair Value Measurements section for further disclosures regarding fair value of financial instruments.

The fair value of derivative assets and derivative liabilities is adjusted for credit risk. The impact of credit risk was immaterial for all periods presented.

NOTE 10: Fair Value Measurements

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; (iii) inputs other than quoted prices that are observable for the asset or liability; or (iv) inputs that are derived principally from or corroborated by observable market data by correlation or other means. Level 3 inputs are unobservable inputs for the financial asset or liability.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2018.

	Fair Value Measurement at December 31, 2018			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value

Financial Assets (Liabilities):				
Derivative Contracts - Swaps	$-	$1,558,346	$ -	$1,558,346
Derivative Contracts - Collars	$-	$1,233,819	$ -	$1,233,819

Level 2 – Market Approach - The fair values of the Company’s swaps and collars are based on a third-party pricing model which utilizes inputs that are either readily available in the public market, such as natural gas curves and volatility curves, or can be corroborated from active markets. These values are based upon future prices, time to maturity and other factors. These values are then compared to the values given by our counterparties for reasonableness.

At December 31, 2018, and September 30, 2018, the carrying values of cash and cash equivalents, receivables, and payables are considered to be representative of their respective fair values due to the short-term maturities of those instruments. Financial instruments include long-term debt, which the valuation is classified as Level 2 as the carrying amount of the Company’s revolving credit facility approximates fair value because the interest rates are reflective of market rates. The estimated current market interest rates are based primarily on interest rates currently being offered on borrowings of similar amounts and terms. In addition, no valuation input adjustments were considered necessary relating to nonperformance risk for the debt agreements.

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

FORWARD-LOOKING STATEMENTS AND RISK FACTORS

Forward-Looking Statements for fiscal 2019 and later periods are made in this document. Such statements represent estimates by management based on the Company's historical operating trends, its proved oil, NGL and natural gas reserves and other information currently available to management. The Company cautions that the Forward-Looking Statements provided herein are subject to all the risks and uncertainties incident to the acquisition, development and marketing of, and exploration for oil, NGL and natural gas reserves. Investors should also read the other information in this Form 10-Q and the Company's 2018 Annual Report on Form 10-K where risk factors are presented and further discussed. For all the above reasons, actual results may vary materially from the Forward-Looking Statements and there is no assurance that the assumptions used are necessarily the most likely to occur.

RESULTS OF OPERATIONS

THREE MONTHS ENDED DECEMBER 31, 2018 – COMPARED TO THREE MONTHS ENDED DECEMBER 31, 2017

Overview:

The Company recorded a first quarter 2019 net income of $12,735,940, or $0.75 per share, as compared to net income of $13,784,939, or $0.81 per share, in the 2018 quarter. The change in net income (loss) was principally the result of gain on assets sales, gains on derivative contracts, increased lease bonuses and decreased LOE and DD&A; largely offset by changes in tax provision (benefit) and decreased oil, NGL and natural gas sales. These items are further discussed below.

Oil, NGL and Natural Gas Sales:

Oil, NGL and natural gas sales decreased $676,700 or 5% for the 2019 quarter. Oil, NGL and natural gas sales were down due to decreased oil, NGL and gas sales volumes of 9%, 14% and 22%, respectively, and decreases in NGL prices of 10%, partially offset by increased natural gas prices of 32%. The following table outlines the Company's production and average sales prices for oil, NGL and natural gas for the three-month periods of fiscal 2019 and 2018:

	Oil Bbls Sold	Average Price	NGL Bbls Sold	Average Price	Mcf Sold	Average Price	Mcfe Sold	Average Price
Three months ended								
12/31/2018	82,828	$ 54.08	62,262	$ 23.37	1,893,990	$ 3.31	2,764,530	$ 4.42
12/31/2017	90,837	$ 53.83	72,401	$ 26.10	2,442,384	$ 2.50	3,421,812	$ 3.77

Overall production is down due to the natural decline of the production base and, to a lesser extent, the result of marginal property divestitures. This was partially offset by the production from new royalty and working interest wells. The oil production decrease is primarily from the Eagle Ford Shale properties; a result of naturally declining production, as well as downtime related to workovers and lateral cleanouts in the first quarter of 2019. This decrease was somewhat offset by the acquisition of Bakken producing properties in August of 2018 and new well drilling in the Permian Basin. The NGL production decrease was attributed to the natural decline in the liquid-rich production from the prior year's drilling program in the Anadarko Basin Woodford Shale. The decrease was partially offset by new well drilling in Arkoma Woodford and STACK in Oklahoma and Permian Basin in New Mexico. Decreased gas production was due to naturally declining production in the Anadarko Woodford and Arkoma Woodford Shales, well workovers in the Arkoma Woodford Shale and, to a lesser extent, marginal property divestitures. These decreases were partially offset by new drilling in the STACK play in western Oklahoma.

Total production in the first quarter of 2018 saw significant increases due to our substantial 2017 drilling program in the Arkoma Woodford (8 wells), Anadarko Woodford (6 wells) and Eagle Ford (10 wells) shales, which began production just before or during the quarter. All of these wells had significantly higher than average NRI's and were near their peak production rates during this time. Since the first quarter of 2018, the production from these wells has come down from their peak rates, as these wells have fairly steep initial decline curves. The Company's total production has remained basically flat from the second quarter of 2018 through the end of fiscal 2018. The total production decline in the first quarter of 2019 is only around 6% when compared to the last three quarters of 2018. We believe that this is important to note, as it reflects the strength of the new royalty production on our mineral acreage during this period of significantly less capital expenditures to drill and complete wells as compared to our fiscal 2017 program.

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Production for the last five quarters was as follows:

Quarter ended	Oil Bbls Sold	NGL Bbls Sold	Mcf Sold	Mcfe Sold
12/31/2018	82,828	62,262	1,893,990	2,764,530
9/30/2018	83,118	58,886	2,088,258	2,940,282
6/30/2018	80,298	67,142	2,082,700	2,967,340
3/31/2018	82,312	56,747	2,107,920	2,942,274
12/31/2017	90,837	72,401	2,442,384	3,421,812

Lease Bonuses and Rental Income:

Lease bonuses and rental income increased $417,598 in the 2019 quarter. The increase was due to a higher level of leasing by the Company during the 2019 quarter.

Gains (Losses) on Derivative Contracts:

The fair value of derivative contracts was a net asset of $2,792,165 as of December 31, 2018, and a net liability of $334,877 as of December 31, 2017. We had a net gain on derivative contracts of $4,506,780 in the 2019 quarter as compared to a net loss of $493,852 in the 2018 quarter. The change is principally due to the oil collars and fixed price swaps being more favorable in the 2019 quarter, as NYMEX oil futures experienced a large decrease in price during the quarter in relation their previous position to the collars and the fixed prices of the swaps. During the 2018 quarter, the oil collars and fixed price swaps experienced an unfavorable change as the NYMEX futures prices (at that time) increased from where they were at the end of the fourth quarter in 2017. The Company utilizes derivative contracts for the purpose of protecting its return on investments.

Gain on Asset Sales:

Gain on asset sales was $9,096,938 in the 2019 quarter. In the 2019 quarter, the Company sold mineral acreage in Lea and Eddy Counties, New Mexico, for a gain of $9,096,938. In the 2018 quarter, the Company did not have a gain on asset sales.

Lease Operating Expenses (LOE):

Total LOE decreased $522,139 or 14% in the 2019 quarter. LOE per Mcfe increased in the 2019 quarter to $1.12 compared to $1.06 in the 2018 quarter. LOE related to field operating costs decreased $332,545 or 18% in the 2019 quarter compared to the 2018 quarter. Field operating costs were $.54 per Mcfe in both the 2019 and 2018 quarters.

The decrease in LOE related to field operating costs was coupled with a decrease in handling fees (primarily gathering, transportation and marketing costs) of $189,594 in the 2019 quarter compared to the 2018 quarter. On a per Mcfe basis, these handling fees were $0.58 in the 2019 quarter as compared to $0.52 in the 2018 quarter. This increase in rate was mainly due to lower cost oil production declining 9%. Natural gas sales bear the large majority of the handling fees while oil sales incur a much smaller amount. Handling fees are charged either as a percent of sales or based on production volumes.

Depreciation, Depletion and Amortization (DD&A):

DD&A decreased $1,462,138 or 28% in the 2019 quarter. DD&A in the 2019 quarter was $1.38 per Mcfe as compared to $1.54 per Mcfe in the 2018 quarter. DD&A decreased $448,726 as a result of this $.16 decrease in the DD&A rate per Mcfe. An additional decrease of $1,013,412 was the result of production decreasing 19% in the 2019 quarter compared to the 2018 quarter. The rate decrease is mainly due to new production from royalty interest only wells and wells with lower finding costs coming on since the 2018 quarter. This decrease was also coupled with the decline in production from the Eagle Ford Shale properties, which have higher finding costs. The Eagle Ford production was down due to natural production decline as well as some downtime related to workovers and lateral cleanouts in the 2019 quarter.

Interest Expense:

Interest expense increased $107,791 or 25% in the 2019 quarter. The increase was the result of a higher interest rates partially offset by a lower average outstanding debt balance during the 2019 quarter.

Loss on Asset Sales and Other Expense (Income):

Loss on asset sales and other expense (income) changed from an income of $295,658 in the 2018 quarter to a $16,637 expense in the 2019 quarter. This change was primarily due to the Company receiving higher miscellaneous income (which is included in this line item on the Statement of Operations) of $575,816 partially offset by a loss on sale of non-core assets of $272,236, in the 2018 quarter. The increased miscellaneous income in the 2018 quarter was primarily related to forfeited earnest money of $460,500 from a potential asset sale that did not close when the counterparty could not secure funding.

Income Taxes:

Income taxes changed $16,281,000, from a $12,710,000 benefit in the 2018 quarter to a $3,571,000 provision in the 2019 quarter. This was mainly the result of the Tax Cuts and Jobs Act enacted in December 2017 that reduced the US federal corporate tax rate from 35% to 21%. The $12,652,000 tax benefit of this law change on our existing deferred tax liabilities was recorded in the 2018 quarter and directly affected the effective tax rate for the 2018 quarter. The effective tax rate changed from a 1182% benefit in the 2018 quarter to a 22% provision in the 2019 quarter.

When a provision for income taxes is expected for the year, federal and Oklahoma excess percentage depletion decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is recorded.

LIQUIDITY AND CAPITAL RESOURCES

The Company had positive working capital of $9,104,804 at December 31, 2018, compared to positive working capital of $2,509,050 at September 30, 2018. The change in working capital was mainly due to the net change in receivables (payables) for derivative contracts as of December 31, 2018.

Liquidity:

Cash and cash equivalents were $455,793 as of December 31, 2018, compared to $532,502 at September 30, 2018, a decrease of $76,709. Cash flows for the three months ended December 31 are summarized as follows:

Net cash provided (used) by:

	2018	2017	Change
Operating activities	$4,009,743	$7,198,583	$(3,188,840)
Investing activities	7,227,999	(4,421,737)	11,649,736
Financing activities	(11,314,451)	(2,766,210)	(8,548,241)
Increase (decrease) in cash and cash equivalents	$(76,709)	$10,636	$(87,345)

Operating activities:

Net cash provided by operating activities decreased $3,188,840 during the 2019 period, as compared to the 2018 period, primarily the result of the following:

- Increased net payments on derivative contracts of $2,056,585.
- Receipts of oil, NGL and natural gas sales (net of production taxes and gathering, transportation and marketing costs) and other decreased $1,119,180.
- Increased receipts from leasing of fee mineral acreage of $429,682.
- Increased payments for G&A and other expense of $321,832.
- Increased interest payments of $104,356.

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Investing activities:

Net cash provided by investing activities increased $11,649,736 during the 2019 period, as compared to the 2018 period, primarily due to lower payments of $3,538,941 for drilling and completion activity and higher net proceeds from the sale of assets of $8,539,188, partially offset by higher acquisition costs of $423,000 during 2019.

Financing activities:

Net cash used by financing activities increased $8,548,241 during the 2019 period, as compared to the 2018 period, primarily the result of higher net payments on long-term debt of $7,677,780 and increased stock repurchases of $868,459.

Capital Resources:

Capital expenditures to drill and complete wells decreased $3,538,941 (71%) from the 2018 to the 2019 period. The Company has working interest in seven Eagle Ford Shale wells currently being completed. The outstanding capital commitment on those wells, net of prepayments, is approximately $1.1 million.

On November 30, 2018, the Company closed on a transaction to sell certain mineral acreage and producing oil and gas properties, primarily located in Lea and Eddy Counties, New Mexico, to a private buyer for total net consideration of $9.1 million cash. The cash from the sale was used to reduce the Company's outstanding bank debt. Like the vast majority of Panhandle's mineral acreage, these minerals were purchased by Panhandle several years ago for a minimal cost. At the time of sale, the assets had been completely amortized and therefore had no net book value. The total value received was a gain on the sale of assets in the first quarter of 2019. The Company utilized a like-kind exchange under IRS Code 1031 to defer income tax on all of the sale price by offsetting it with the Bakken mineral acreage that was purchased on August 21, 2018, as well as some smaller acquisitions, using a qualified exchange accommodation agreement.

Since the Company is not the operator of any of its oil and natural gas properties, it is difficult for us to predict the level of future participation in and precise timing of the drilling and completion of new wells. Thus, capital expenditures for drilling and completion projects are difficult to forecast.

The Company received lease bonus payments during 2019 totaling $528,374. Looking forward, the cash flow benefit from bonus payments associated with the leasing of drilling rights on the Company's mineral acreage is very difficult to project as the Company's mineral acreage position is so diverse and spread across several states. However, management will continue to strategically evaluate the merit of proactively leasing certain of the Company's mineral acres.

With continued oil and natural gas price volatility, management continues to evaluate opportunities for product price protection through additional hedging of the Company's future oil and natural gas production. See NOTE 9– "Derivatives" for a complete list of the Company's outstanding derivative contracts.

The use of the Company's cash provided by operating activities and resultant change to cash is summarized in the table below:

	Three months

	ended December 31, 2018
Cash provided by operating activities	$4,009,743
Cash provided (used) by:	
Capital expenditures - acquisitions	(423,000)
Capital expenditures - drilling and completion of wells	(1,445,939)
Quarterly dividends of $.04 per share	(673,892)
Treasury stock purchases	(1,140,559)
Net borrowings (payments) on credit facility	(9,500,000)
Proceeds from sale of assets	9,096,938
Net cash used	(4,086,452)
Net increase (decrease) in cash	$(76,709)

(16)

Outstanding borrowings on the credit facility at December 31, 2018, were $41,500,000.

Looking forward, the Company expects to fund overhead costs, capital additions related to the drilling and completion of wells, acquisitions, treasury stock purchases, if any, and dividend payments from cash provided by operating activities, cash on hand and borrowings utilizing our bank credit facility. The Company intends to use any excess cash to reduce existing bank debt. The Company had availability of $38,500,000 at December 31, 2018, under its revolving credit facility and is in compliance with its debt covenants (current ratio, debt to trailing 12-month EBITDA, as defined by bank agreement, and restricted payments limited by leverage ratio). The debt covenants limit the maximum ratio of the Company’s debt to EBITDA to no more than 4:1.

The borrowing base under the credit facility was redetermined in January 2019 and left unchanged at $80 million, which is a level that is expected to provide ample liquidity for the Company to continue to execute its normal operating strategies. The next redetermination is scheduled for July 2019.

On November 6, 2017, the Company filed a shelf registration statement with the SEC on Form S-3. This filing gives us the authorization to sell up to $75 million in securities, including common stock, preferred stock, debt securities, warrants and units in amounts to be determined at the time of an offering. Any such offering, if it does occur, may happen in one or more transactions. The specific terms of any securities to be sold will be described in supplemental filings with the SEC. The registration statement will expire on November 6, 2020. The Company currently has no plans to issue securities under the shelf registration statement.

Based on expected capital expenditure levels, anticipated cash provided by operating activities for 2019 and availability under its credit facility, the Company has sufficient liquidity to fund its ongoing operations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Critical accounting policies are those the Company believes are most important to portraying its financial conditions and results of operations and also require the greatest amount of subjective or complex judgments by management. Judgments and uncertainties regarding the application of these policies may result in materially different amounts being reported under various conditions or using different assumptions. There have been no material changes to the critical accounting policies previously disclosed in the Company’s Form 10-K for the fiscal year ended September 30, 2018.

ITEM 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Oil, NGL and natural gas prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of oil, NGL and natural gas price trends, and there remains a rather wide divergence in the opinions held in the industry. The Company can be significantly impacted by changes in oil and natural gas prices. The market price of oil, NGL and natural gas in 2019 will impact the amount of cash generated from operating activities, which will in turn impact the level of the Company’s capital expenditures and production. Excluding the impact of the Company’s 2019 derivative contracts, the price sensitivity in 2019 for each $1.00 per barrel change in wellhead oil price is $336,565 for operating revenue based on the Company’s prior year oil volumes. The price sensitivity in 2019 for each $0.10 per Mcf change in wellhead natural gas price is $872,126 for operating revenue based on the Company’s prior year natural gas volumes.

Commodity Price Risk

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in oil and natural gas prices. The Company does not enter into these derivatives for speculative or trading purposes. The Company's derivative contracts are currently with Bank of Oklahoma and Koch Supply and Trading LP. The derivative contracts with Bank of Oklahoma are secured under its credit facility with Bank of Oklahoma. The derivative contracts with Koch are unsecured. These arrangements cover only a portion of the Company's production and provide only partial price protection against declines in oil and natural gas prices. These derivative contracts expose the Company to risk of financial loss and limit the benefit of future increases in prices. For the Company's oil fixed price swaps, a change of $1.00 in the NYMEX WTI forward strip prices would result in a change to pre-tax operating income of approximately $111,600. For the Company's oil collars, a change of $1.00 in the NYMEX WTI forward strip prices would result in a change to pre-tax operating income of approximately $89,000. For the Company's natural gas fixed price swaps, a change of $.10 in the NYMEX Henry Hub forward strip pricing would result in a change to pre-tax operating income of approximately $292,300.

Financial Market Risk

Operating income could also be impacted, to a lesser extent, by changes in the market interest rates related to the Company's credit facilities. The revolving loan bears interest at the BOK prime rate plus from 0.50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%. At December 31, 2018, the Company had $41,500,000 outstanding under this facility and the effective interest rate was 4.63%. At this point, the Company does not believe that its liquidity has been materially affected by the interest rate uncertainties noted in the last few years and the Company does not believe that its liquidity will be significantly impacted in the near future.

ITEM 4 CONTROLS AND PROCEDURES

The Company maintains "disclosure controls and procedures," as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company's President/Chief Executive Officer and Vice President/Chief Financial Officer and Controller, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The Company's disclosure controls and procedures have been designed to meet, and management believes they do meet, reasonable assurance standards. Based on their evaluation as of the end of the fiscal period covered by this report, the Chief Executive Officer and Chief Financial Officer have concluded, subject to the limitations noted above, the Company's disclosure controls and procedures were effective to ensure material information relating to the Company is made known to them. There were no changes in the Company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting made during the fiscal quarter or subsequent to the date the assessment was completed.

PART II OTHER INFORMATION

ITEM 2 UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the three months ended December 31, 2018, the Company repurchased shares of the Company's common stock as summarized in the table below.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program
10/1 - 10/31/18	-	$ -	-	$ 681,128
11/1 - 11/30/18	-	$ -	-	$ 681,128
12/1 - 12/31/18	74,457	$ 15.32	74,457	$ 1,040,569
Total	74,457	$ 15.32	74,457	

Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan in March 2010, as amended in May 2018, the board of directors approved to continue to allow the Company to repurchase up to $1.5 million of the Company's common stock at management's discretion. The Board added language to clarify that this is intended to be an evergreen program as the repurchase of an additional $1.5 million of the Company's common stock is authorized and approved whenever the previous $1.5 million is utilized. In addition, the number of shares allowed to be purchased by the Company under the Repurchase Program is no longer capped at an amount equal to the aggregate number of shares of common stock (i) awarded pursuant to the Company's Amended 2010 Restricted Stock Plan, (ii) contributed by the Company to its ESOP, and (iii) credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors.

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ITEM 6 EXHIBITS

(a)	EXHIBITS	Exhibit 31.1 – Certification under Section 302 of the Sarbanes-Oxley Act of 2002
		Exhibit 31.2 – Certification under Section 302 of the Sarbanes-Oxley Act of 2002
		Exhibit 32.1 – Certification under Section 906 of the Sarbanes-Oxley Act of 2002
		Exhibit 32.2 – Certification under Section 906 of the Sarbanes-Oxley Act of 2002
		Exhibit 101.INS – XBRL Instance Document
		Exhibit 101.SCH – XBRL Taxonomy Extension Schema Document
		Exhibit 101.CAL – XBRL Taxonomy Extension Calculation Linkbase Document
		Exhibit 101.LAB – XBRL Taxonomy Extension Labels Linkbase Document
		Exhibit 101.PRE – XBRL Taxonomy Extension Presentation Linkbase Document
		Exhibit 101.DEF – XBRL Taxonomy Extension Definition Linkbase Document
(b)	Form 8-K	Dated (12/4/18), item 8.01 – Other Events
	Form 8-K	Dated (12/19/18), item 5.02 – Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers

SIGNATURES

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

PANHANDLE OIL AND GAS INC.

	PANHANDLE OIL AND GAS INC.
February 7, 2019 Date	/s/ Paul F. Blanchard Jr. Paul F. Blanchard Jr., President and Chief Executive Officer
February 7, 2019 Date	/s/ Robb P. Winfield Robb P. Winfield, Vice President, Chief Financial Officer and Controller

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