PANHANDLE OIL & GAS INC
Form 10-Q
August 07, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the period ended June 30, 2017

Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from   to

Commission File Number 001-31759

PANHANDLE OIL AND GAS INC.

(Exact name of registrant as specified in its charter)

OKLAHOMA	73-1055775
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Grand Centre Suite 300, 5400 N Grand Blvd., Oklahoma City, Oklahoma 73112

(Address of principal executive offices)

Registrant's telephone number including area code (405) 948-1560

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.   Yes   No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company
Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

Outstanding shares of Class A Common stock (voting) at August 7, 2017: 16,671,016

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The following defined terms are used in this report:

“Bbl” barrel.

“Board” board of directors.

“BTU” British Thermal Units.

“Company” Panhandle Oil and Gas Inc.

“completion” the process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.

“DD&A” depreciation, depletion and amortization .

“dry hole” exploratory or development well that does not produce crude oil and/or natural gas in economic quantities.

“EBITDA” earnings before interest, taxes, depreciation and amortization (including impairment). This is a Non-GAAP measure.

“ESOP” the Panhandle Oil and Gas Inc. Employee Stock Ownership and 401(k) Plan, a tax qualified, defined contribution plan.

“exploratory well” a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir.

“FASB” the Financial Accounting Standards Board.

“field” an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“G&A” general and administrative costs.

“gross acres” the total acres in which an interest is owned.

“held by production” or “HBP” an oil and gas lease continued into effect into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

“horizontal drilling” a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

“IDC” intangible drilling costs.

“Independent Consulting Petroleum Engineer(s)” or “Independent Consulting Petroleum Engineering Firm” DeGolyer and MacNaughton of Dallas, Texas.

“LOE” lease operating expense.

“Mcf” thousand cubic feet.

"Mcfe" natural gas stated on an Mcf basis and crude oil and natural gas liquids converted to a thousand cubic feet of natural gas equivalent by using the ratio of one Bbl of crude oil or natural gas liquids to six Mcf of natural gas.

"Mmbtu" million BTU.

"minerals", "mineral acres" or "mineral interests" fee mineral acreage owned in perpetuity by the Company.

"net acres" the sum of the fractional interests owned in gross acres.

"NGL" natural gas liquids.

"NYMEX" New York Mercantile Exchange.

"Panhandle" Panhandle Oil and Gas Inc.

"play" term applied to identified areas with potential oil and/or natural gas reserves.

"proved reserves" the quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain.

"royalty interest" well interests in which the Company does not pay a share of the costs to drill, complete and operate a well, but receives a much smaller proportionate share (as compared to a working interest) of production.

"SEC" the United States Securities and Exchange Commission.

"undeveloped acreage" lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

"working interest" well interests in which the Company pays a share of the costs to drill, complete and operate a well and receives a proportionate share of production.

"WTI" West Texas Intermediate.

Fiscal year references

All references to years in this report, unless otherwise noted, refer to the Company's fiscal year end of September 30. For example, references to 2017 mean the fiscal year ended September 30, 2017.

Fiscal quarter references

All references to quarters in this report, unless otherwise noted, refer to the Company's fiscal quarter based on a fiscal year end of September 30. For example, references to first quarter mean the quarter of October 1 through December 31.

References to oil and natural gas properties

References to oil and natural gas properties inherently include natural gas liquids associated with such properties.

PART 1. FINANCIAL INFORMATION

PANHANDLE OIL AND GAS INC.

CONDENSED BALANCE SHEETS

Assets	June 30, 2017 (unaudited)	September 30, 2016
Current assets:		
Cash and cash equivalents	$560,892	$471,213
Oil, NGL and natural gas sales receivables (net of allowance for uncollectable accounts)	5,851,996	5,287,229
Refundable income taxes	571,986	83,874
Derivative contracts, net	1,439,686	-
Other	222,675	419,037
Total current assets	8,647,235	6,261,353
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	443,928,828	434,469,093
Non-producing oil and natural gas properties	7,462,082	7,574,649
Other	1,064,172	1,069,658
	452,455,082	443,113,400
Less accumulated depreciation, depletion and amortization	(255,806,129)	(251,707,749)
Net properties and equipment	196,648,953	191,405,651
Investments	168,209	157,322
Derivative contracts, net	11,711	-
Total assets	$205,476,108	$197,824,326
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$3,791,830	$2,351,623
Derivative contracts, net	-	403,612
Accrued liabilities and other	1,758,153	1,718,558
Total current liabilities	5,549,983	4,473,793
Long-term debt	50,000,000	44,500,000
Deferred income taxes, net	30,825,007	30,676,007
Asset retirement obligations	3,114,867	2,958,048
Derivative contracts, net	-	24,659
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized,	280,938	280,938

16,863,004 issued at June 30, 2017, and September 30, 2016		
Capital in excess of par value	2,531,822	3,191,056
Deferred directors' compensation	3,367,432	3,403,213
Retained earnings	112,962,754	112,482,284
	119,142,946	119,357,491
Less treasury stock, at cost; 191,988 shares at June 30, 2017, and 262,708 shares at September 30, 2016	(3,156,695)	(4,165,672)
Total stockholders' equity	115,986,251	115,191,819
Total liabilities and stockholders' equity	$205,476,108	$197,824,326

(See accompanying notes)

(1)

PANHANDLE OIL AND GAS INC.

CONDENSED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2017	2016	2017	2016
Revenues:	(unaudited)		(unaudited)	
Oil, NGL and natural gas sales	$9,997,898	$7,365,898	$27,788,018	$22,557,372
Lease bonuses and rentals	819,591	4,281,095	3,991,752	7,188,152
Gains (losses) on derivative contracts	1,619,697	(1,782,903)	1,658,347	(842,726)
	12,437,186	9,864,090	33,438,117	28,902,798
Costs and expenses:				
Lease operating expenses	3,391,079	3,520,196	9,545,990	10,274,085
Production taxes	390,387	196,733	1,129,785	747,714
Depreciation, depletion and amortization	4,714,350	5,959,482	13,654,268	18,963,017
Provision for impairment	-	-	10,788	11,849,064
Loss (gain) on asset sales and other	11,447	17,223	98,445	(187,692)
Interest expense	306,161	331,117	884,928	1,034,027
General and administrative	1,796,004	1,570,134	5,358,114	5,133,657
	10,609,428	11,594,885	30,682,318	47,813,872
Income (loss) before provision (benefit) for income taxes	1,827,758	(1,730,795)	2,755,799	(18,911,074)
Provision (benefit) for income taxes	567,000	(944,000)	263,000	(7,887,000)
Net income (loss)	$1,260,758	$(786,795)	$2,492,799	$(11,024,074)
Basic and diluted earnings (loss) per common share (Note 3)	$0.07	$(0.05)	$0.15	$(0.65)
Basic and diluted weighted average shares outstanding:				
Common shares	16,668,814	16,582,416	16,639,090	16,575,117
Unissued, directors' deferred compensation shares	254,891	263,649	277,294	259,382
	16,923,705	16,846,065	16,916,384	16,834,499
Dividends declared per share of common stock and paid in period	$0.04	$0.04	$0.12	$0.12

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.

STATEMENTS OF STOCKHOLDERS' EQUITY

Nine Months Ended June 30, 2017

	Class A voting Common Stock Shares	Amount	Capital in Excess of Par Value	Deferred Directors' Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2016	16,863,004	$280,938	$3,191,056	$3,403,213	$112,482,284	(262,708)	$(4,165,672)	$115,191,819
Purchase of treasury stock	-	-	-	-	-	(17,119)	(407,677)	(407,677)
Issuance of treasury shares to ESOP	-	-	(2)	-	-	(1)	(16)	(18)
Restricted stock awards	-	-	454,854	-	-	-	-	454,854
Net income (loss)	-	-	-	-	2,492,799	-	-	2,492,799
Dividends ($.12 per share)	-	-	-	-	(2,012,329)	-	-	(2,012,329)
Distribution of restricted stock to officers and directors	-	-	(968,617)	-	-	60,624	969,239	622
Distribution of deferred directors' compensation	-	-	(145,469)	(301,963)	-	27,216	447,431	(1)
Increase in deferred directors' compensation charged to expense	-	-	-	266,182	-	-	-	266,182

Balances at June 30, 2017 (unaudited)	16,863,004	$280,938	$2,531,822	$3,367,432	$112,962,754	(191,988)	$(3,156,695)	$115,986,251

Nine Months Ended June 30, 2016

	Class A voting Common Stock Shares	Amount	Capital in Excess of Par Value	Deferred Directors' Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2015	16,863,004	$280,938	$2,993,119	$3,084,289	$125,446,473	(302,623)	$(4,800,144)	$127,004,675
Purchase of treasury stock	-	-	-	-	-	(7,477)	(117,165)	(117,165)
Restricted stock awards	-	-	644,783	-	-	-	-	644,783
Net income (loss)	-	-	-	-	(11,024,074)	-	-	(11,024,074)
Dividends ($.12 per share)	-	-	-	-	(2,007,658)	-	-	(2,007,658)
Distribution of restricted stock to officers and directors	-	-	(551,256)	-	-	32,005	507,599	(43,657)
Distribution of deferred directors' compensation	-	-	(831)	(10,541)	-	717	11,372	-
Increase in deferred directors' compensation charged to expense	-	-	-	247,835	-	-	-	247,835
Balances at June 30, 2016 (unaudited)	16,863,004	$280,938	$3,085,815	$3,321,583	$112,414,741	(277,378)	$(4,398,338)	$114,704,739

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.

CONDENSED STATEMENTS OF CASH FLOWS

	Nine months ended June 30, 2017 (unaudited)	2016
Operating Activities		
Net income (loss)	$2,492,799	$(11,024,074)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	13,654,268	18,963,017
Impairment	10,788	11,849,064
Provision for deferred income taxes	149,000	(10,344,000)
Gain from leasing fee mineral acreage	(3,999,632)	(7,187,377)
Proceeds from leasing fee mineral acreage	4,026,283	7,494,570
Net (gain) loss on sales of assets	87,161	(271,080)
Directors' deferred compensation expense	266,182	247,835
Restricted stock awards	454,854	644,783
Other	2,897	73,527
Cash provided (used) by changes in assets and liabilities:		
Oil, NGL and natural gas sales receivables	(564,767)	3,472,291
Fair value of derivative contracts	(1,879,668)	5,901,280
Refundable production taxes	-	476,001
Other current assets	196,362	69,237
Accounts payable	(127,375)	(698,593)
Income taxes receivable	(488,112)	345,897
Income taxes payable	-	659,319
Accrued liabilities	40,197	(118,403)
Total adjustments	11,828,438	31,577,368
Net cash provided by operating activities	14,321,237	20,553,294
Investing Activities		
Capital expenditures, including dry hole costs	(18,011,721)	(3,359,518)
Investments in partnerships	(18,531)	50,126
Proceeds from sales of assets	718,700	627,547
Net cash provided (used) by investing activities	(17,311,552)	(2,681,845)
Financing Activities		
Borrowings under debt agreement	16,702,602	8,560,234
Payments of loan principal	(11,202,602)	(24,360,234)
Purchases of treasury stock	(407,677)	(117,165)
Payments of dividends	(2,012,329)	(2,007,658)
Excess tax benefit on stock-based compensation	-	(44,000)
Net cash provided (used) by financing activities	3,079,994	(17,968,823)
Increase (decrease) in cash and cash equivalents	89,679	(97,374)
Cash and cash equivalents at beginning of period	471,213	603,915

Cash and cash equivalents at end of period	$560,892	$506,541
Supplemental Schedule of Noncash Investing and Financing Activities:		
Additions to asset retirement obligations	$60,276	$8,156
Gross additions to properties and equipment	$19,579,304	$3,529,104
Net (increase) decrease in accounts payable for properties and equipment additions	(1,567,583)	(169,586)
Capital expenditures and acquisitions, including dry hole costs	$18,011,721	$3,359,518

(See accompanying notes)

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 2016 Annual Report on Form 10-K.

Adoption of New Accounting Pronouncements

In April 2015, the FASB issued Accounting Standards Update ("ASU") 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The update requires that debt issuance costs related to a recognized debt liability, such as senior notes, term loans and note payables, be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation of debt discounts. Under previous guidance, debt issuance costs were required to be presented in the balance sheet as an asset. The recognition and measurement guidance for debt issuance costs is not affected by the update. For public entities, the guidance is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years.

In August 2015, the FASB issued ASU 2015-15, Interest—Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements, which allows for line-of-credit arrangements to be handled consistently with the presentation of debt issuance costs prior to ASU 2015-03 issued in April 2015. For public entities, the guidance is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years.

The Company adopted ASU 2015-03 and ASU 2015-15 as of December 31, 2016. The Company elected to continue to show debt issuance costs associated with its credit facility (Company's only debt) as assets versus a direct reduction of the debt liability. Therefore, the adoption had no impact on the Company's current and previously reported balance sheets, shareholders' equity, results of operations, or cash flows. In accordance with ASU 2015-15, unamortized debt issuance costs associated with the Company's credit facility, which amounted to $172,613 and $263,584 as of June 30, 2017, and September 30, 2016, respectively, remain reflected in "Other property and equipment" on the balance sheets.

In November 2015, the FASB issued ASU 2015-17, Balance Sheet Classification of Deferred Taxes. The update requires that deferred income tax assets and liabilities be classified as noncurrent in the balance sheet. For public entities, the guidance is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years.

The Company early adopted ASU 2015-17 as of December 31, 2016, on a retrospective basis to all prior balance sheet periods presented. As a result of the adoption, the Company reclassified $310,900 as of September 30, 2016, from "Deferred income taxes" in current assets to “Deferred income tax, net” in long term liabilities on the balance sheets. Adoption of ASU 2015-17 had no impact on the Company's current and previously reported shareholders' equity, results of operations or cash flows. The affected prior period deferred income tax account balances presented throughout this report on Form 10-Q have been adjusted to reflect the retroactive adoption of ASU 2015-17.

In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments, which addresses certain issues where diversity in practice was identified and may change how an entity classifies certain cash receipts and cash payments on its statement of cash flows. The new guidance also clarifies how the predominance principle should be applied when cash receipts and cash payments have aspects of more than one class of cash flows. This guidance will generally be applied retrospectively and is effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those years. Early adoption is permitted. All of the amendments in ASU 2016-15 are required to be adopted at the same time.

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The Company early adopted ASU 2016-15 as of December 31, 2016. As a result of the adoption, the Company reclassified “Proceeds from leasing fee mineral acreage”, which totaled $4,026,283 and $7,494,570 for the nine months ended June 30, 2017, and June 30, 2016, respectively, from Investing Activities to Operating Activities on the Condensed Statements of Cash Flows as these transactions are made in our normal course of business and represent operating activities based on the application of the predominance principle. As another result of this adoption, we are also electing to classify our distributions received from equity method investments using the Cumulative Earnings Approach. Distributions received are considered returns on investment and classified as cash inflows from operating activities, unless the investor’s cumulative distributions received less distributions received in prior periods that were determined to be returns of investment exceed cumulative equity in earnings recognized by the investor. When such an excess occurs, the current-period distribution up to this excess should be considered a return of investment and classified as cash inflows from investing activities. This election did not have any impact on our cash flow statements as the Company was already applying this approach. Adoption of ASU 2016-15 had no impact on the Company's current and previously reported shareholders' equity, results of operations or balance sheets. The affected prior period balances in the Condensed Statements of Cash Flows presented throughout this report on Form 10-Q have been adjusted to reflect the retroactive adoption of ASU 2016-15.

In March 2016, the FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The new guidance is intended to improve the accounting for employee share-based payments and affect all organizations that issue share-based payment awards to their employees. The guidance changes how companies account for certain aspects of share-based payment awards, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The standard is effective for interim and annual reporting periods beginning after December 15, 2016, and will be adopted either prospectively, retrospectively or using a modified retrospective transition approach depending on the topic covered in the standard. Early adoption is permitted for any organization in any interim or annual period. On a prospective basis companies will no longer record excess tax benefits and deficiencies in additional paid-in capital. Instead, excess tax benefits and deficiencies will be recognized as income tax expense or benefit in the income statement. This is expected to result in increased volatility in income tax expense/benefit and corresponding variations in the relationship between income tax expense/benefit and pre-tax income/loss from period to period. Also, companies will have to present excess tax benefits and deficiencies as operating activities on the statement of cash flows (prospectively or retrospectively). The new guidance will also require an employer to classify as a financing activity in its statement of cash flows the cash paid to a tax authority when shares are withheld to satisfy the employer’s statutory income tax withholding obligation.

The Company early adopted ASU 2016-09 as of October 1, 2016. As a result of the adoption, the Company recorded $228,000 of excess tax benefits from stock-based compensation in the “Provision (benefit) for income taxes” on the Condensed Statements of Operations in the nine-month period ended June 30, 2017, versus “Capital in excess of par” on the Condensed Balance Sheets in the nine-month period ended June 30, 2016, as was previously required. This part of the guidance is to be applied prospectively, so the prior period balances have not been reclassified. The Company also presented excess tax benefits from stock-based compensation in the “Operating Activities” section of the Condensed Statements of Cash Flows in the current period versus the “Financing Activities” section of the Condensed Statements of Cash Flows as was previously presented. The Company has elected to apply this part of the guidance prospectively, so the prior period balances have not been reclassified. The guidance also requires that companies present employees taxes paid upon vesting as financing activities on the statement of cash flows (Purchases of Treasury Stock). This requirement had no impact on the Company, as this has been the practice historically. The Company is also electing to account for forfeitures of awards as they occur, instead of estimating a forfeiture amount. A cumulative-effect adjustment to retained earnings was not necessary for this transition as there were no material forfeitures estimated or incurred in the past. The adoption of this ASU could cause volatility in the effective tax rate going forward.

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) 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 simplified 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. For public entities, the guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted for all public business entities upon issuance. 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. Lessees and lessors may not apply a full retrospective transition approach. We are assessing the potential impact that this update will have on our financial statements.

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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 public companies for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. We are assessing the potential impact that this update will have on our financial statements.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, which will supersede nearly all existing revenue recognition guidance under GAAP. The standard's core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. We are evaluating our existing revenue recognition policies to determine whether any contracts in the scope of the guidance will be affected by the new requirements. The standard is effective for us 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. We are currently evaluating the potential impact that this update will have on our financial statements and the transition method that will be elected.

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.

NOTE 2: Income Taxes

The Company's provision for income taxes differs from the statutory rate primarily due to estimated federal and state benefits generated from estimated 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. The adoption of ASU 2016-09 will also increase volatility in the effective tax rate going forward. Excess tax benefits and deficiencies of stock based compensation will be recognized as income tax expense (benefit) in the statement of operations prospectively versus additional paid in capital in the equity section of the balance sheet as was previously required.

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 proportional effect of these items on the effective tax rate may be significant. The effective tax rate for the nine months ended June 30, 2017, was a 10% provision as compared to a 42% benefit for the nine months ended June 30, 2016. The effective tax rate for the quarter ended June 30, 2017, was a 31% provision as compared to a 55% benefit for the quarter ended June 30, 2016.

NOTE 3: 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 4: 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, 2018. 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 with a net book value of $155,271,161 at June 30, 2017. The interest rate is based on BOK prime plus from 0.375% to 1.125%, or 30 day LIBOR plus from 1.875% to 2.625%. 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 a larger percent of the borrowing base is advanced. At June 30, 2017, the effective interest rate was 3.26%.

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 (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. In June 2017, 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 treasury stock. In addition, the Company is required to maintain certain financial ratios, a current ratio (as defined by 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 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 June 30, 2017, the Company was in compliance with the covenants of the loan agreement and has $30,000,000 of availability under its outstanding credit facility.

NOTE 5: 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 6: 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 retain, attract 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.

On December 9, 2016, the Company awarded 6,845 non-performance based shares and 20,531 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. The non-performance and performance based shares had a fair value on their award date of $176,260 and $292,884, respectively. The fair value for the performance and the non-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 9, 2016, through December 9, 2019).

On December 31, 2016, the Company awarded 8,916 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, 2017. The restricted stock contains non-forfeitable rights to receive dividends and voting rights during the vesting period. These non-performance based shares had a fair value on their award date of $209,970.

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The following table summarizes the Company's pre-tax compensation expense for the three and nine months ended June 30, 2017 and 2016, related to the Company's performance based and non-performance based restricted stock.

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2017	2016	2017	2016
Performance based, restricted stock	$51,302	$40,380	$181,820	$350,270
Non-performance based, restricted stock	85,919	96,308	273,034	294,513
Total compensation expense	$137,221	$136,688	$454,854	$644,783

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 June 30, 2017	
	Unrecognized Compensation Cost	Weighted Average Period (in years)
Performance based, restricted stock	$ 318,920	1.98
Non-performance based, restricted stock	317,247	1.51
Total	$ 636,167	

Upon vesting, shares are expected to be issued out of shares held in treasury.

NOTE 7: 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 geological and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological 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.

NOTE 8: 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 the three months ended June 30, 2017 and 2016, the assessment resulted in impairment provisions on producing properties of $0 and $0, respectively. For the nine months ended June 30, 2017 and 2016, the assessment resulted in impairment provisions on producing properties of $10,788 and $11,849,064, respectively. 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.

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NOTE 9: Capitalized Costs

As of June 30, 2017, and September 30, 2016, non-producing oil and natural gas properties include costs of $0 and $5,917, respectively, on exploratory wells which were drilling and/or testing.

NOTE 10: 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. All of the Company's derivative contracts are with Bank of Oklahoma and are secured under its credit facility with Bank of Oklahoma. The derivative instruments have settled or will settle based on the prices below.

Derivative contracts in place as of June 30, 2017

Contract period	Production volume covered per month	Index	Contract price
Natural gas costless collars			
January - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.80 floor / $3.47 ceiling
January - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.00 floor / $3.35 ceiling
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.80 floor / $3.35 ceiling
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.35 ceiling
April - December 2017	30,000 Mmbtu	NYMEX Henry Hub	$3.00 floor / $3.65 ceiling
May - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.00 floor / $3.60 ceiling
May - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.20 floor / $3.65 ceiling
January - March 2018	100,000 Mmbtu	NYMEX Henry Hub	$3.50 floor / $3.95 ceiling
January - March 2018	150,000 Mmbtu	NYMEX Henry Hub	$3.40 floor / $3.95 ceiling
January - December 2018	40,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.35 ceiling
Natural gas fixed price swaps			
January - December 2017	25,000 Mmbtu	NYMEX Henry Hub	$3.100
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.070
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.210
April - December 2017	30,000 Mmbtu	NYMEX Henry Hub	$3.300
July - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.510
January - March 2018	50,000 Mmbtu	NYMEX Henry Hub	$3.700
January - March 2018	75,000 Mmbtu	NYMEX Henry Hub	$3.575
January - March 2018	100,000 Mmbtu	NYMEX Henry Hub	$3.520
Oil costless collars			
January - December 2017	3,000 Bbls	NYMEX WTI	$50.00 floor / $55.00 ceiling
January - December 2017	3,000 Bbls	NYMEX WTI	$52.00 floor / $58.00 ceiling
January - December 2017	3,000 Bbls	NYMEX WTI	$53.00 floor / $57.75 ceiling

April - December 2017	2,000 Bbls	NYMEX WTI	$50.00 floor / $57.50 ceiling
July - December 2017	5,000 Bbls	NYMEX WTI	$45.00 floor / $56.25 ceiling
Oil fixed price swaps			
January - December 2017	3,000 Bbls	NYMEX WTI	$53.89
April - December 2017	2,000 Bbls	NYMEX WTI	$54.20
January - March 2018	4,000 Bbls	NYMEX WTI	$54.00

(10)

Derivative contracts in place as of September 30, 2016

Contract period	Production volume covered per month	Index	Contract price
Natural gas costless collars			
April - October 2016	200,000 Mmbtu	NYMEX Henry Hub	$1.95 floor / $2.40 ceiling
October - December 2016	70,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.05 ceiling
October - December 2016	50,000 Mmbtu	NYMEX Henry Hub	$2.90 floor / $3.40 ceiling
November 2016 - March 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.25 floor / $3.65 ceiling
November 2016 - March 2017	80,000 Mmbtu	NYMEX Henry Hub	$2.25 floor / $3.95 ceiling
November 2016 - March 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.60 floor / $3.25 ceiling
January - June 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.85 floor / $3.35 ceiling
January - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.80 floor / $3.47 ceiling
January - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.00 floor / $3.35 ceiling
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.80 floor / $3.35 ceiling
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$2.75 floor / $3.35 ceiling
Natural gas fixed price swaps			
October 2016	100,000 Mmbtu	NYMEX Henry Hub	$2.410
October 2016 - March 2017	25,000 Mmbtu	NYMEX Henry Hub	$3.200
November 2016 - April 2017	80,000 Mmbtu	NYMEX Henry Hub	$2.955
January - December 2017	25,000 Mmbtu	NYMEX Henry Hub	$3.100
April - December 2017	50,000 Mmbtu	NYMEX Henry Hub	$3.070
Oil costless collars			
July - December 2016	3,000 Bbls	NYMEX WTI	$35.00 floor / $49.00 ceiling
October - December 2016	3,000 Bbls	NYMEX WTI	$40.00 floor / $47.25 ceiling
October 2016 - March 2017	3,000 Bbls	NYMEX WTI	$40.00 floor / $58.50 ceiling
October 2016 - March 2017	3,000 Bbls	NYMEX WTI	$45.00 floor / $54.00 ceiling
October 2016 - March 2017	3,000 Bbls	NYMEX WTI	$45.00 floor / $55.50 ceiling

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 $1,451,397 as of June 30, 2017, and a net liability of $428,271 as of September 30, 2016.

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 June 30, 2017, and September 30, 2016. The Company has offset all amounts subject to master netting agreements in the Company's Condensed Balance Sheets at June 30, 2017, and September 30, 2016.

	June 30, 2017			September 30, 2016			
	Fair Value (a)			Fair Value (a)			
	Commodity Contracts			Commodity Contracts			
	Current Assets	Current Liabilities	Non-Current Assets	Current Assets	Current Liabilities	Non-Current Assets	Non-Current Liabilities
Gross amounts recognized	$1,492,208	$52,522	$ 11,711	$68,235	$471,847	$ 4,759	$ 29,418
Offsetting adjustments	(52,522)	(52,522)	-	(68,235)	(68,235)	(4,759)	(4,759)
Net presentation on Condensed Balance Sheets (11)	$1,439,686	$-	$ 11,711	$-	$403,612	$ -	$ 24,659

(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 11: 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 June 30, 2017.

	Fair Value Measurement at June 30, 2017			
	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	$-	$ 732,223	$ -	$732,223
Derivative Contracts - Collars	$-	$ -	$ 719,174	$719,174

Level 2 – Market Approach - The fair values of the Company’s swaps 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, 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.

Level 3 – The fair values of the Company’s costless collar contracts are based on a pricing model which utilizes inputs that are unobservable or not readily available in the public market. These values are based upon future prices, volatility, time to maturity and other factors. These values are then compared to the values given by our counterparties for reasonableness.

The significant unobservable inputs for Level 3 derivative contracts include market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of our derivative contracts. An increase (decrease) in the volatility of oil and natural gas prices will decrease (increase) the fair value of oil and natural gas derivatives and adverse changes to our counterparties' creditworthiness will decrease the fair value of our derivatives.

The following table represents quantitative disclosures about unobservable inputs for Level 3 Fair Value Measurements.

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value June 30, 2017
Oil Collars	Oil price volatility curve	0% - 21.50%	13.73%	$ 459,049
Natural Gas Collars	Gas price volatility curve	0% - 34.96%	19.80%	$ 260,125

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A reconciliation of the Company's derivative contracts classified as Level 3 measurements is presented below. All gains and losses are presented on the Gains (losses) on derivative contracts line item on our Condensed Statements of Operations.

	Derivatives
Balance of Level 3 as of October 1, 2016	$(316,658)
Total gains or (losses)	
Included in earnings	1,222,713
Included in other comprehensive income (loss)	-
Purchases, issuances and settlements	(186,881)
Transfers in and out of Level 3	-
Balance of Level 3 as of June 30, 2017	$719,174

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Quarter Ended June 30,			
	2017		2016	
	Fair Value	Impairment	Fair Value	Impairment
Producing Properties (a)	$-	$ -	$-	$-

	Nine Months Ended June 30,			
	2017		2016	
	Fair Value	Impairment	Fair Value	Impairment
Producing Properties (a)	$7,868	$ 10,788	$9,741,650	$11,849,064

(a) At the end of each quarter, the Company assesses the carrying value of its producing properties for impairment. This assessment utilizes estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of future oil and natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs and an applicable discount rate commensurate with risk of the underlying cash flow estimates. These assessments identified certain properties with carrying value in excess of their calculated fair values.

At June 30, 2017, and September 30, 2016, the fair value of financial instruments approximated their carrying amounts. Financial instruments include long-term debt, which the valuation is classified as Level 3 and is based on a valuation technique that requires inputs that are both unobservable and significant to the overall fair value measurement. The fair value measurement of our long-term debt is valued using a discounted cash flow model that calculates the present value of future cash flows pursuant to the terms of the debt agreements and applies estimated current market interest 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.

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 2017 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 2016 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.

LIQUIDITY AND CAPITAL RESOURCES

The Company had positive working capital of $3,097,252 at June 30, 2017, compared to positive working capital of $1,787,560 at September 30, 2016. The change in working capital was mainly due to increased receivables for derivative contracts as of June 30, 2017.

Liquidity:

Cash and cash equivalents were $560,892 as of June 30, 2017, compared to $471,213 at September 30, 2016, an increase of $89,679. Cash flows for the nine months ended June 30 are summarized as follows:

Net cash provided (used) by:

	2017	2016	Change
Operating activities	$14,321,237	$20,553,294	$(6,232,057)
Investing activities	(17,311,552)	(2,681,845)	(14,629,707)
Financing activities	3,079,994	(17,968,823)	21,048,817
Increase (decrease) in cash and cash equivalents	$89,679	$(97,374)	$187,053

Operating activities:

Net cash provided by operating activities decreased $6,232,057 during the 2017 period, as compared to the 2016 period, primarily the result of the following:

- Decreased receipts from leasing of fee mineral acreage of $3,468,287.
- Receipts of oil, NGL and natural gas sales (net of production taxes and gathering, transportation and marketing costs) and other increased $321,884.
- Decreased income tax payments of $890,707.
- Decreased net receipts on derivative contracts of $5,279,865.
- Decreased interest payments of $187,099.
- Decreased payments for G&A and other expenses of $136,294.
- Decreased payments for field operating expenses of $980,111.

Investing activities:

Net cash used by investing activities increased $14,629,707 during the 2017 period, as compared to the 2016 period, primarily due to higher payments of $14,652,203 for drilling and completion activity during 2017.

Financing activities:

Net cash used by financing activities decreased $21,048,817 during the 2017 period, as compared to the 2016 period, primarily the result of lower net payments on long-term debt of $21,300,000.

Capital Resources:

Capital expenditures to drill and complete wells increased $14,652,203 (436%) from the 2016 to the 2017 period. The Company agreed to participate in eight BP operated southeastern Oklahoma Woodford wells with an average working interest of 20% and an average net revenue interest of 27.4%. All eight wells have been drilled. Four of those wells were completed and began producing in the second quarter. The remaining four wells have been completed and started producing in the third quarter of 2017. The Company agreed to participate in six Anadarko Basin Woodford wells, operated by Cimarex Energy, with 17.5% working interest

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and 16.25% net revenue interest. All six wells have been drilled, completed and will start producing in the fourth quarter of 2017. The Company is also participating in a continuous ten-well drilling program utilizing one rig on our Eagle Ford Shale leasehold. All ten wells in this program have been drilled and the first two wells were completed and started producing in April 2017. The next four wells are completing and will start producing in the fourth quarter of 2017. The remaining four wells should be completed and begin producing in the first quarter of 2018.

Activity from these three plays will significantly increase our capital expenditures in 2017 compared to 2016. Capital expenditures on these wells in 2017 will be partially funded by utilization of the Company's credit facility.

Since the Company is not the operator of any of its oil and natural gas properties, it is extremely difficult for us to predict levels of future participation in the drilling and completion of new wells and their associated capital expenditures. This makes capital expenditures for drilling and completion projects difficult to forecast.

Even though oil, NGL and natural gas production volumes decreased 11% on an Mcfe basis during the 2017 period, as compared to the 2016 period, the Company experienced material oil and natural gas daily volumes growth during the third quarter and anticipates that oil, NGL and natural gas daily volumes will continue to increase as new wells in the Anadarko Basin Woodford (Cana) and Eagle Ford Shale begin to produce throughout the remainder of 2017.

The Company received lease bonus payments during the nine months of 2017 totaling approximately $4.0 million. 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 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 10 – "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:

	Nine months ended June 30, 2017
Cash provided by operating activities	$14,321,237
Cash provided (used) by:	
Capital expenditures - drilling and completion of wells	(18,011,721)
Quarterly dividends of $.12 per share	(2,012,329)
Treasury stock purchases	(407,677)
Net borrowings (payments) on credit facility	5,500,000
Other investing and financing activities	700,169
Net cash used	(14,231,558)
Net increase (decrease) in cash	$89,679

Outstanding borrowings on the credit facility at June 30, 2017, were $50,000,000.

Looking forward, the Company expects to fund overhead costs, capital additions related to the drilling and completion of wells, treasury stock purchases, if any, and dividend payments from cash provided by operating activities, cash on hand and borrowings utilizing our bank credit facility. Any excess cash is intended to be used to reduce existing bank debt. The Company had availability ($30,000,000 at June 30, 2017) 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 dividends as a percent of operating cash flow). 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 June 2017 and left unchanged at $80 million, which is a level that is expected to provide ample liquidity for the Company to continue to employ its normal operating strategies. The next redetermination is scheduled for December 2017.

Based on expected capital expenditure levels, anticipated cash provided by operating activities for 2017 and availability under its credit facility, the Company has sufficient liquidity to fund its ongoing operations.

RESULTS OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2017 – COMPARED TO THREE MONTHS ENDED JUNE 30, 2016

Overview:

The Company recorded a third quarter 2017 net income of $1,260,758, or $0.07 per share, as compared to a net loss of $786,795, or $0.05 per share, in the 2016 quarter. The change in net income (loss) was principally the result of decreased DD&A, increased oil, NGL and natural gas sales, and gains on derivative contracts; partially offset by decreased lease bonuses and decreased benefit from income taxes. These items are further discussed below.

Oil, NGL and Natural Gas Sales:

Oil, NGL and natural gas sales increased $2,632,000 or 36% for the 2017 quarter. Oil, NGL and natural gas sales were up due to increases in oil, NGL and natural gas prices of 14%, 29% and 66%, respectively, and increased natural gas sales volumes of 7%, partially offset by decreases in oil and NGL sales volumes of 15% and 3%, respectively. 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 2017 and 2016:

	Oil Bbls Sold	Average Price	NGL Bbls Sold	Average Price	Mcf Sold	Average Price	Mcfe Sold	Average Price
Three months ended								
6/30/2017	75,467	$ 44.38	39,337	$ 16.63	2,265,091	$ 2.65	2,953,915	$ 3.38
6/30/2016	88,732	$ 38.91	40,477	$ 12.93	2,112,567	$ 1.60	2,887,821	$ 2.55

The oil production decrease is principally due to declining production from the Anadarko Basin Woodford Shale, the Bakken Shale in North Dakota and the Marmaton in Western Oklahoma also contributed to the reduction. The NGL production decrease primarily resulted from declining production in the Anadarko Basin Granite Wash, the southeastern Oklahoma Woodford Shale and the Anadarko Basin Woodford Shale, all in Oklahoma. The decline was partially offset by an increase in NGL production in the Eagle Ford Shale in South Texas. The increase in natural gas production was the result of a material increase in production in the southeastern Oklahoma Woodford. The increase was partially offset by declining production from the Fayetteville Shale in Arkansas, the Anadarko Basin Woodford Shale and the Marmaton in western Oklahoma.

Production for the last five quarters was as follows:

Quarter ended	Oil Bbls Sold	NGL Bbls Sold	Mcf Sold	Mcfe Sold

6/30/2017	75,467	39,337	2,265,091	2,953,915
3/31/2017	66,547	33,836	1,748,909	2,351,207
12/31/2016	75,636	35,651	1,849,692	2,517,414
9/30/2016	78,398	44,598	1,940,749	2,678,725
6/30/2016	88,732	40,477	2,112,567	2,887,821

Lease Bonuses and Rentals:

Lease bonuses and rentals decreased $3,461,504 in the 2017 quarter. The decrease was mainly due to the Company completing two large mineral lease packages covering several counties in Oklahoma in the 2016 quarter.

Gains (Losses) on Derivative Contracts:

The fair value of derivative contracts was a net asset of $1,451,397 as of June 30, 2017, and a net liability of $1,690,516 as of June 30, 2016. We had a net gain on derivative contracts of $1,619,697 in the 2017 quarter as compared to a net loss of $1,782,903 in the 2016 quarter. The change is principally due to the oil and natural gas collars and fixed price swaps being more beneficial in the 2017 quarter, as NYMEX oil and natural gas futures experienced decreases in price in relation to the collars and the fixed prices of the swaps.

Lease Operating Expenses (LOE):

LOE decreased $129,117 or 4% in the 2017 quarter. LOE per Mcfe decreased in the 2017 quarter to $1.15 compared to $1.22 in the 2016 quarter. LOE related to field operating costs decreased $268,764 in the 2017 quarter compared to the 2016 quarter, a 14% decrease. Field operating costs were $.58 per Mcfe in the 2017 quarter as compared to $.69 per Mcfe in the 2016 quarter. The decrease in rate in the 2017 quarter is principally the result of significant new production coming on, decreased operating costs in several fields and the company selling some high operating costs wells in 2017.

The decrease in LOE related to field operating costs was partially offset by an increase in handling fees (primarily gathering, transportation and marketing costs) of $139,647 in the 2017 quarter compared to the 2016 quarter. On a per Mcfe basis, these fees increased $.04 due mainly to a 15% decrease in oil production versus a 7% increase in natural gas production. 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.

Production Taxes:

Production taxes increased $193,654 or 98% in the 2017 quarter as compared to the 2016 quarter. The increase in amount is primarily the result of increased oil, NGL and natural gas sales of $2,632,000 during the 2017 quarter. Production taxes as a percentage of oil, NGL and natural gas sales were 3.9% for the 2017 quarter and 2.7% for the 2016 quarter. The increase in tax rate is mainly the result of production tax refunds being received in the 2016 quarter that were in excess of our previous estimates.

Depreciation, Depletion and Amortization (DD&A):

DD&A decreased $1,245,132 or 21% in the 2017 quarter. DD&A in the 2017 quarter was $1.60 per Mcfe as compared to $2.06 per Mcfe in the 2016 quarter. DD&A decreased $1,381,528 as a result of this $.46 decrease in the DD&A rate per Mcfe. An offsetting increase of $136,396 was the result of production increasing 2% in the 2017 quarter compared to the 2016 quarter. The rate decrease is mainly due to higher oil, NGL and natural gas prices utilized in the reserve calculations during the 2017 quarter, as compared to the 2016 quarter, lengthening the economic life of wells thus resulting in higher projected remaining reserves on a significant number of wells. The Company had new high volume wells with low finding costs begin producing in the 2017 quarter, which also contributed to the rate decrease.

General and Administrative Costs (G&A):

G&A costs increased $225,870 or 14% in the 2017 quarter. This increase is primarily related to increases in personnel expenses due to the timing of accrued incentive compensation and increases in legal expenses.

Income Taxes:

Income taxes changed $1,511,000 (from a $944,000 benefit in the 2016 quarter to a $567,000 provision in the 2017 quarter), the result of a $3,558,553 change from pre-tax loss to pre-tax income in the 2017 quarter, compared to the 2016 quarter, and a decrease in the effective tax rate from a 55% benefit in the 2016 quarter to a 31% provision in the 2017 quarter. When a provision for income taxes is expected for the year (as is the case for 2017), 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, as was the case for 2016.

NINE MONTHS ENDED JUNE 30, 2017 – COMPARED TO NINE MONTHS ENDED JUNE 30, 2016

Overview:

The Company recorded a nine month net income of $2,492,799, or $0.15 per share, in the 2017 period, as compared to a net loss of $11,024,074, or $0.65 per share, in the 2016 period. The change in net income (loss) was principally the result of decreased DD&A and provision for impairment, increased oil, NGL and natural gas sales, and gains on derivative contracts; partially offset by decreased lease bonuses and decreased benefit from income taxes. These items are further discussed below.

Oil, NGL and Natural Gas Sales:

Oil, NGL and natural gas sales increased $5,230,646 or 23% for the 2017 period. Oil, NGL and natural gas sales were up due to increases in oil, NGL and natural gas prices of 30%, 51% and 56%, respectively, offset by a decrease in oil, NGL and natural gas sales volumes of 24%, 14% and 8%, respectively. The following table outlines the Company’s production and average sales prices for oil, NGL and natural gas for the nine month periods of fiscal 2017 and 2016:

	Oil Bbls Sold	Average Price	NGL Bbls Sold	Average Price	Mcf Sold	Average Price	Mcfe Sold	Average Price
Nine months ended								
6/30/2017	217,650	$ 46.06	108,824	$ 18.08	5,863,692	$ 2.69	7,822,536	$ 3.55
6/30/2016	285,854	$ 35.35	126,462	$ 11.95	6,343,628	$ 1.72	8,817,524	$ 2.56

The oil production decrease is principally the result of production decline from the Eagle Ford Shale in South Texas. To a lesser extent, declining production from the Anadarko Basin Granite Wash and the Marietta Basin Woodford, both in Oklahoma and the Bakken Shale in North Dakota also contributed to the reduction. The NGL production decrease primarily resulted from declining production in the Anadarko Basin Woodford Shale, Anadarko Basin Granite Wash, Roger Mills Marmaton and the Ardmore Basin Woodford Shale, all in Oklahoma. The decline was partially offset by an increase in NGL production in the southeastern Oklahoma Woodward Shale. The reduction in natural gas production was largely the result of declining production from the Fayetteville Shale in Arkansas, the Anadarko Basin Woodford Shale, Anadarko Basin Granite Wash and the Marmaton in western Oklahoma. The decline was partially offset by a material increase in production in the southeastern Oklahoma Woodford Shale.

Lease Bonuses and Rentals:

Lease bonuses and rentals decreased $3,196,400 in the 2017 period. The decrease was mainly due to the Company completing three large mineral lease packages covering several counties in Oklahoma and Cochran County, Texas, in the 2016 period.

Gains (Losses) on Derivative Contracts:

The fair value of derivative contracts was a net asset of $1,451,397 as of June 30, 2017, and a net liability of $1,690,516 as of June 30, 2016. We had a net gain on derivative contracts of $1,658,347 in the 2017 period as compared to a net loss of $842,726 recorded in the 2016 period. The change is principally due to the oil and natural gas collars and fixed price swaps being more beneficial in the 2017 period, as NYMEX oil and natural gas futures were falling below the floor of the collars and the fixed prices of the swaps in the 2017 period and they were rising above the ceiling of the collars and the fixed prices of the swaps in the 2016 period.

Lease Operating Expenses (LOE):

LOE decreased $728,095 or 7% in the 2017 period. LOE per Mcfe increased in the 2017 period to $1.22 compared to $1.17 in the 2016 period. LOE related to field operating costs decreased $990,469 in the 2017 period compared to the 2016 period, a 16% decrease. Field operating costs were $.66 per Mcfe in the 2017 period as compared to $.70 per Mcfe in the 2016 period. The decrease in rate in the 2017 period is principally the result of decreased operating costs in several fields and the company selling some high operating costs wells in 2017.

The decrease in LOE related to field operating costs was partially offset with an increase in handling fees (primarily gathering, transportation and marketing costs) of $262,374 in the 2017 period compared to the 2016 period. On a per Mcfe basis, these fees increased $.09 due mainly to a 24% decrease in oil production versus an 8% decrease in natural gas production. 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 $5,308,749 or 28% in the 2017 period. DD&A in the 2017 period was $1.75 per Mcfe as compared to $2.15 per Mcfe in the 2016 period. DD&A decreased $3,168,922 as a result of this $.40 decrease in the DD&A rate per Mcfe. An additional decrease of $2,139,827 was the result of production decreasing 11% in the 2017 period compared to the 2016 period. The rate decrease is mainly due to higher oil, NGL and natural gas prices utilized in the reserve calculations during the 2017 period, as compared to 2016 period, lengthening the economic life of wells thus resulting in higher projected remaining reserves on a significant number of wells. Impairment expense in the prior year lowered our depreciable basis, which also contributed to the rate decrease.

Provision for Impairment:

The provision for impairment decreased $11,838,276 in the 2017 period compared to the 2016 period. During the 2016 period, impairment of $11,849,064 was recorded on thirty-nine fields. Four oil and liquids rich fields accounted for approximately $9.5 million (Anadarko Basin Granite Wash - $5.9 million, Cheyenne West - $1.7 million, Ellis County Marmaton - $1.0 million and Permian Basin - $.9 million) of the impairment mainly due to continued low oil, NGL and natural gas prices during that time. During the 2017 period, impairment of $10,788 was recorded on three small fields.

Income Taxes:

Income taxes changed $8,150,000 (from a benefit of $7,887,000 in the 2016 period to a $263,000 provision in the 2017 period), the result of a $21,666,873 change from pre-tax loss to pre-tax income in the 2017 period compared to the 2016 period. The effective tax rate for the 2017 and 2016 periods was a 10% provision and a 42% benefit, respectively. 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, as was the case for the 2016 period. The effective tax rate for the 2017 period was also impacted by excess tax benefits from stock based compensation recorded to income tax expense (benefit) during the first quarter of 2017.

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, 2016.

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 2017 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 2017 derivative contracts, the price sensitivity in 2017 for each $1.00 per barrel change in wellhead oil price is $364,252 for operating revenue based on the Company’s prior year oil volumes. The price sensitivity in 2017 for each $0.10 per Mcf change in wellhead natural gas price is $828,438 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. All of our outstanding derivative contracts are with Bank of Oklahoma and are secured. 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 $52,000. 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 $81,000. 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 $189,000. For the Company's natural gas collars, a change of $.10 in the NYMEX Henry Hub forward strip pricing would result in a change to pre-tax operating income of approximately $201,000.

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 0.375% to 1.125%, or 30 day LIBOR plus from 1.875% to 2.625%. At June 30, 2017, the Company had $50,000,000 outstanding under this facility and the effective interest rate was

3.26%. 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 June 30, 2017, the Company did not repurchased shares of the Company's common stock.

Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan in March 2010, as amended in March 2014, the Board of Directors approved repurchase of up to $1.5 million of the Company's common stock, from time to time, 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. Pursuant to previously adopted board resolutions, the purchase of an additional $1.5 million of the Company's common stock became authorized and approved effective June 26, 2013. The shares are held in treasury and are accounted for using the cost method. Effective May 14, 2014, the Board adopted resolutions to allow management to repurchase the Company's common stock at their discretion.

ITEM 6 EXHIBITS

(a) EXHIBITS Exhibit 31.1 and 31.2 – Certification under Section 302 of the Sarbanes-Oxley Act of 2002
Exhibit 32.1 and 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 (5/22/17), item 8.01 – Other Events
	Form 8-K	Dated (8/1/17), item 5.02 – Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers

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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.

August 7, 2017 Date	/s/ Paul F. Blanchard Jr. Paul F. Blanchard Jr., President and Chief Executive Officer
August 7, 2017 Date	/s/ Robb P. Winfield Robb P. Winfield, Vice President, Chief Financial Officer and Controller

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