UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934.

Date of Report: (Date of Earliest Event Reported) **November 6, 2017**

PANHANDLE OIL AND GAS INC.

(Exact name of registrant as specified in its charter)

OKLAHOMA	**001-31759**	**73-1055775**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

5400 North Grand Blvd., Suite 300 Oklahoma City, OK	**73112**
(Address of principal executive offices)	(Zip code)

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

Not Applicable
(Former name or former address if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act
☐ Pre-commencement communications pursuant to Rule 14d-2 (b) under the Exchange Act
☐ Pre-commencement communications pursuant to Rule 13e-4 (c) under the Exchange Act

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

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. ☐

ITEM 8.01 Other Events

Panhandle Oil and Gas Inc. (the “Company”), is filing this Current Report on Form 8-K to update the presentation of certain financial information and related disclosures contained in its Form 10-K for the year ended September 30, 2016 (the “2016 Form 10-K”) which was filed with the Securities and Exchange Commission (“SEC”) on December 12, 2016. This Form 8-K reflects the presentation of the Company’s adoption of Accounting Standards Update (“ASU”) 2016-15 and ASU 2015-17. Subsequent to the filing of the Company’s 2016 Form 10-K, the Company early adopted ASU 2016-15 and ASU 2015-17 and reclassified “Proceeds from leasing fee mineral acreage” from Investing Activities to Operating Activities on the Statements of Cash Flows and reclassified Deferred income taxes from current assets and current liabilities to long term liabilities on the Company’s condensed balance sheets (the “Condensed Balance Sheets”). The change had no impact on net income (loss), net income (loss) per basic or diluted share amounts.

This Form 8-K retrospectively revises our financial statements as of September 30, 2016, and for all periods presented, to reflect the adoption of ASU 2016-15 and ASU 2015-17. This update is consistent with the presentation of “Proceeds from leasing fee mineral acreage” on the Condensed Statements of Cash Flows and the “Deferred income taxes” on the Condensed Balance Sheets included in the Company’s Form 10-Q for the quarters ended December 31, 2016, March 31, 2017, and June 30, 2017, filed with the SEC on February 6, 2017, May 5, 2017, and August 7, 2017, respectively. The retrospectively revised Items contained in the Company’s 2016 Form 10-K are presented in Exhibits 99.1, 99.2 and 99.3 to this Form 8-K.

The exhibits to this Current Report on Form 8-K supersede the following Items in the 2016 Form 10-K to reflect, retrospectively, the changes resulting from the reclassification of the Company’s “Proceeds from leasing fee mineral acreage” from Investing Activities to Operating Activities on the Statements of Cash Flows and the “Deferred income taxes” on the Condensed Balance Sheets for all periods presented:

- Part II, Item 6. Revised Selected Financial Data – 2016 Form 10-K
- Part II, Item 7. Revised Management’s Discussion and Analysis of Financial Condition and Results of Operations (“MD&A”) – 2016 Form 10-K
- Part II, Item 8. Revised Financial Statements and Supplementary Data – 2016 Form 10-K

All other information in the 2016 Form 10-K remains unchanged. Unaffected portions of the 2016 Form 10-K have not been repeated in, and are not amended or modified by, this Current Report on Form 8-K or Exhibits 99.1, 99.2 and 99.3 to this Form 8-K. This Current Report on Form 8-K does not reflect events occurring subsequent to the filing of the 2016 Form 10-K and does not modify or update the disclosures therein in any way, other than as required to reflect the reclassifications as described above and as set forth in the exhibits attached hereto. Without limitation to the foregoing, this Current Report on Form 8-K does not purport to update the MD&A in the 2016 Form 10-K for any information, uncertainties, risks, events or trends occurring or known to management. For developments since the filing of the 2016 Form 10-K, please refer to the Third Quarter 2017 Form 10-Q, as well as other filings of the Company made with the SEC. The information in this Current Report on Form 8-K should be read in conjunction with the 2016 Form 10-K and such subsequent filings.

ITEM 9.01 Financial Statements and Exhibits

(d) *Exhibits*

Exhibit Number	**Description**
23.1	Consent of Independent Registered Public Accounting Firm
23.2	Consent of DeGolyer and MacNaughton
99.1	Part II, Item 6. Revised Selected Financial Data – 2016 Form 10-K
99.2	Part II, Item 7. Revised Management's Discussion and Analysis of Financial Condition and Results of Operations – 2016 Form 10-K
99.3	Part II, Item 8. Revised Financial Statements and Supplementary Data – 2016 Form 10-K
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

SIGNATURE

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

PANHANDLE OIL AND GAS INC.

By: /s/ Paul F. Blanchard Jr.
Paul F. Blanchard Jr.,
President and CEO

DATE: November 6, 2017

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the reference to our firm under the caption "Experts" in the Registration Statement (Form S-3) and related Prospectus of Panhandle Oil and Gas Inc. for the registration of common stock, preferred stock, warrants, debt securities and units and to the incorporation by reference of our reports dated December 12, 2016, except for the impact of the matters discussed in Note 1 pertaining to the adoption of ASU 2015-17 and ASU 2016-15, as to which the date is November 6, 2017, with respect to the financial statements of Panhandle Oil and Gas Inc. and our report dated December 12, 2016, with respect to the effectiveness of internal control over financial reporting of Panhandle Oil and Gas Inc. included in Panhandle Oil and Gas Inc.'s Current Report on Form 8-K dated November 6, 2017, filed with the Securities and Exchange Commission.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
November 6, 2017

EXHIBIT 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

October 16, 2017

Panhandle Oil and Gas Inc.
Grand Centre, Suite 300
5400 North Grand Blvd
Oklahoma City, OK 73112

Ladies and Gentlemen:

We hereby consent to the inclusion in this Current Report on Form 8-K of Panhandle Oil and Gas Inc. (Panhandle) of our report dated October 3, 2016, with respect to estimates of reserves and future net revenue of Panhandle, as of September 30, 2016, and to all references to our firm included in this Current Report. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and our reserves report as of September 30, 2016 and March 31, 2017, and references thereto, into Panhandle's Registration Statement on Form S-3.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

EXHIBIT 99.1

ITEM 6 SELECTED FINANCIAL DATA (1)

The following table summarizes financial data of the Company for its last five fiscal years and should be read in conjunction with Item 7 – “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 8 – “Financial Statements and Supplementary Data,” including the Notes thereto, included elsewhere in this report.

	As of and for the year ended September 30,				
	2016	2015	2014	2013	2012
Revenues					
Oil, NGL and natural gas sales	$ 31,411,353	$ 54,533,914	$ 82,846,528	$ 60,605,878	$ 40,818,434
Lease bonuses and rentals	7,735,785	2,010,395	423,328	938,846	7,152,991
Gains (losses) on derivative contracts	(86,355)	13,822,506	247,414	611,024	73,822
Income from partnerships	2,400	515,278	893,954	733,372	487,070
	39,063,183	70,882,093	84,411,224	62,889,120	48,532,317
Costs and expenses					
Lease operating expense	13,590,089	17,472,408	13,912,792	11,861,403	9,141,970
Production taxes	1,071,632	1,702,302	2,694,118	1,834,840	1,449,537
Exploration costs	31,589	48,404	86,017	9,795	979,718
Depreciation, depletion and amortization	24,487,565	23,821,139	21,896,902	21,945,768	19,061,239
Provision for impairment	12,001,271	5,009,191	1,096,076	530,670	826,508
Loss (gain) on asset sales & other	(2,624,642)	(398,994)	8,378	(942,959)	(88,477)
Interest expense	1,344,619	1,550,483	462,296	157,558	127,970
General and administrative	7,139,728	7,339,320	7,433,183	6,801,996	6,388,856
Bad debt expense (recovery)	19,216	180,499	-	-	-
	57,061,067	56,724,752	47,589,762	42,199,071	37,887,321
Income (loss) before provision (benefit) for income taxes	(17,997,884)	14,157,341	36,821,462	20,690,049	10,644,996
Provision (benefit) for income taxes	(7,711,000)	4,836,000	11,820,000	6,730,000	3,274,000
Net income (loss)	$ (10,286,884)	$ 9,321,341	$ 25,001,462	$ 13,960,049	$ 7,370,996
Basic and diluted earnings (loss) per share	$ (0.61)	$ 0.56	$ 1.49	$ 0.84	$ 0.44
Dividends declared per share	$ 0.16	$ 0.16	$ 0.16	$ 0.14	$ 0.14
Weighted average shares outstanding					
Basic and diluted	16,840,856	16,768,904	16,727,183	16,713,808	16,721,862
Net cash provided by (used in):					
Operating activities	$ 22,639,151	$ 47,624,914	$ 53,099,746	$ 38,425,477	$ 32,637,003
Investing activities	$ 565,617	$ (31,642,385)	$ (122,428,139)	$ (27,403,043)	$ (45,638,510)
Financing activities	$ (23,337,470)	$ (15,888,369)	$ 66,970,977	$ (10,139,362)	$ 11,478,606
Total assets	$197,824,326	$238,825,273	$ 246,640,604	$147,838,430	$135,064,830
Long-term debt	$ 44,500,000	$ 65,000,000	$ 78,000,000	$ 8,262,256	$ 14,874,985
Shareholders' equity	$115,191,819	$127,004,675	$ 119,188,653	$ 95,655,486	$ 83,852,146

(1) The following selected consolidated financial data were derived from our audited consolidated financial statements and should be read in conjunction with, and are qualified by reference to Item 7 - Management’s Discussion and Analysis of Financial Condition and Results of Operations in Exhibit 99.2 and the audited consolidated financial statements and notes thereto in Exhibit 99.3 attached to this Form 8-K. The financial information presented may not be indicative of our future performance.

ITEM 7 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management's Discussion and Analysis ("MD&A") of Financial Condition and Results of Operations should be read in conjunction with a review of Part II, Item 8 - Revised Financial Statements and Supplementary Data included in Exhibit 99.3. Certain statements contained in this MD&A may be deemed to be forward-looking statements. See "Safe Harbor Statement" included in our Annual Report on Form 10-K filed with the Securities and Exchange Commission ("SEC") on December 12, 2016.

BUSINESS OVERVIEW

The Company's principal line of business is to explore for, develop, acquire, produce and sell oil, NGL and natural gas. Results of operations are dependent primarily upon the Company's: existing reserve quantities; costs associated with acquiring, exploring for and developing new reserves; production quantities and related production costs; and oil, NGL and natural gas sales prices.

Fiscal 2016 oil, NGL and natural gas production decreased 20%, 19% and 15%, respectively, from that of 2015. The decrease in oil production was primarily the result of the production decline in the Eagle Ford Shale, which was not offset by new production in the play due to significantly reduced drilling activity. To a lesser extent, declining production from various fields in western Oklahoma, the Texas Panhandle and the Northern Oklahoma Mississippian contributed to the decrease. NGL production volume decreases were largely the result of production decline in the Anadarko Woodford Shale in western and central Oklahoma and the Anadarko Basin Granite Wash in western Oklahoma and the Texas Panhandle. Natural gas production volume decreases were primarily the result of declining production in the Fayetteville Shale. To a lesser extent, declining production from the Anadarko Basin Granite Wash and the southeastern Oklahoma Woodford Shale also contributed to the decrease.

As of September 30, 2016, the Company owned an average 3.5% net revenue interest in 45 wells that were drilling or testing.

The 2016 production decreases in oil, NGL and natural gas, combined with lower oil, NGL and natural gas prices, resulted in a 42% decrease in revenues from the sale of oil, NGL and natural gas. Based on recent forward strip pricing, the Company currently anticipates 2017 average oil, NGL and natural gas prices will be higher than their corresponding average prices in 2016.

The Company's proved developed oil, NGL and natural gas reserves decreased in 2016, compared to 2015, by 26.7 Bcfe, or 25%. The decrease was primarily due to negative pricing revisions.

Other than the lease of office space, the Company had no off balance sheet arrangements during 2016 or prior years.

The following table reflects certain operating data for the periods presented:

	For the Year Ended September 30,				
	2016	Percent Incr. or (Decr.)	2015	Percent Incr. or (Decr.)	2014
Production:					
Oil (Bbls)	364,252	(20%)	453,125	31%	346,387
NGL (Bbls)	171,060	(19%)	210,960	2%	207,688
Natural Gas (Mcf)	8,284,377	(15%)	9,745,223	(10%)	10,773,559
Mcfe	11,496,249	(16%)	13,729,733	(3%)	14,098,009
Average Sales Price:					
Oil (per Bbl)	$36.70	(31%)	$53.12	(43%)	$93.68
NGL (per Bbl)	$12.60	(31%)	$18.25	(44%)	$32.31
Natural Gas (per Mcf)	$1.92	(30%)	$2.73	(33%)	$4.05
Mcfe	$2.73	(31%)	$3.97	(32%)	$5.88

RESULTS OF OPERATIONS

Fiscal Year 2016 Compared to Fiscal Year 2015

Overview

The Company recorded net loss of $10,286,884, or $0.61 per share, in 2016, compared to net income of $9,321,341, or $0.56 per share, in 2015. Revenues decreased in 2016 primarily due to lower oil, NGL and natural gas sales and decreased gains on derivative contracts partially offset by increased lease bonuses received.

Expenses increased in 2016 mainly from a larger provision for impairment and higher DD&A partially offset by a decrease in LOE and production taxes and an increase in gain on sale of assets.

Oil, NGL and Natural Gas Sales

Oil, NGL and natural gas sales decreased $23,122,561, or 42%, for 2016, as compared to 2015. The decrease was due to decreased oil, NGL and natural gas prices of 31%, 31% and 30%, respectively, coupled with lower oil, NGL and natural gas volumes of 20%, 19% and 15%, respectively, in 2016.

The decrease in oil production was primarily the result of natural production decline in the Eagle Ford Shale, which was not offset by new production in the play due to significantly reduced drilling activity. To a lesser extent, declining production from various fields in western Oklahoma, the Texas Panhandle and the Northern Oklahoma Mississippian contributed to the decrease.

NGL production volume decreases were largely the result of natural production decline in the Anadarko Woodford Shale in western and central Oklahoma and the Anadarko Basin Granite Wash in western Oklahoma and the Texas Panhandle.

Natural gas production volume decreases were primarily the result of naturally declining production in the Fayetteville Shale. To a lesser extent, declining production from the Anadarko Basin Granite Wash and the southeastern Oklahoma Woodford Shale also contributed to the decrease.

Production by quarter for 2016 and 2015 was as follows (Mcfe):

	2016	2015
First quarter	3,143,400	3,737,483
Second quarter	2,786,303	3,455,265
Third quarter	2,887,821	3,315,899
Fourth quarter	2,678,725	3,221,086
Total	11,496,249	13,729,733

Lease Bonus and Rentals

Lease bonuses and rentals increased $5,725,390 in 2016. The increase was mainly due to the Company leasing 4,057 net mineral acres in Cochran County, Texas, 663 net mineral acres in Blaine, Canadian, Custer and Dewey Counties, Oklahoma, and 706 net mineral acres in Grady and McClain Counties, Oklahoma, in 2016. In 2015, the Company leased 2,407 net mineral acres in Andrews and Winkler Counties, Texas.

Gains (Losses) on Derivative Contracts

Gains on derivative contracts decreased $13,908,861 in 2016. The decrease was mainly due to the oil and, to a lesser extent, natural gas collars and fixed price swaps being more beneficial in 2015, as NYMEX oil and natural gas futures had fallen further below the floor of the collars and the fixed prices of the swaps. As of September 30, 2016, the Company's natural gas costless collar contracts and natural gas fixed price swaps have expiration dates of October 2016 through December 2017; the oil costless collar contracts have expiration dates of October 2016 through March 2017.

Income from Partnerships

Income from partnerships decreased $512,878 in 2016. This change was primarily due to the Company selling the assets from some of its partnerships in 2016. This was also coupled with lower oil, NGL and natural gas pricing during 2016, as compared to 2015.

Lease Operating Expenses (LOE)

LOE decreased $3,882,319 or 22% in 2016. LOE costs per Mcfe of production decreased from $1.27 in 2015 to $1.18 in 2016. The total LOE decrease was largely due to decreased field operating costs of $2,604,510 in 2016, compared to 2015. Field operating costs were $.70 per Mcfe in 2016, compared to $.78 per Mcfe in 2015, a 10% decrease. This decrease in rate was principally the result of operating efficiencies gained in the Eagle Ford Shale field due to the addition of a salt water disposal system and electrification of the field, as well as fewer workovers.

The decrease in LOE related to field operating costs was coupled with a decrease in handling fees (primarily gathering, transportation and marketing costs) of $1,277,809 in 2016, as compared to 2015. The decrease in the amount in 2016 is the result of decreased oil, NGL and natural gas production and sales. On a per Mcfe basis, these fees decreased $.01. Natural gas sales bear the large majority of the handling fees. Handling fees are charged either as a percent of sales or based on production volumes.

Production Taxes

Production taxes decreased $630,670 or 37% in 2016, as compared to 2015. The decrease in amount was primarily the result of decreased oil, NGL and natural gas sales of $23,122,561 during 2016. Production taxes as a percentage of oil, NGL and natural gas sales increased slightly from 3.1% in 2015 to 3.4% in 2016. The increase in tax rate was the result of the expiration of production tax discounts on some of the Company's horizontally drilled wells in Oklahoma and Arkansas, as well as the increased proportionate sales coming from Texas and North Dakota, where initial tax rates are higher. The low overall production tax rate in both years was due to a large proportion of the Company's oil and natural gas revenues coming from horizontally drilled wells, which are eligible for reduced Oklahoma and Arkansas production tax rates in the first few years of production.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $666,426 in 2016. DD&A per Mcfe was $2.13 in 2016, compared to $1.74 in 2015. DD&A increased $4,541,529 as the result of a $.39 increase in the DD&A rate. This rate increase was principally due to lower oil, NGL and natural gas prices utilized in the reserve calculations during 2016, as compared to 2015, shortening the economic life of wells thus resulting in lower projected remaining reserves on a significant number of wells causing increased units of production DD&A. An offsetting decrease of $3,875,103 was due to oil, NGL and natural gas production volumes decreasing 16% collectively in 2016, compared to 2015.

Provision for Impairment

Provision for impairment increased $6,992,080 in 2016, as compared to 2015. During 2016, impairment of $12,001,271 was recorded on 44 fields primarily in Oklahoma, Kansas and Texas. Two fields in western Oklahoma and the Texas Panhandle accounted for $7,548,533 or 63% of the impairment due mainly to declining oil, NGL and natural gas prices. During 2015, impairment of $5,009,191 was recorded on 27 fields primarily in Oklahoma, Kansas and Texas. One oil field in Hemphill County, Texas, accounted for $1,846,488 of the impairment due mainly to declining oil prices.

Loss (Gain) on Asset Sales and Other

Loss (gain) on asset sales and other was a net gain of $2,624,642 in 2016, as compared to a net gain of $398,994 in 2015. The net gain in 2016 was largely due to the gain on sale of assets from two of the Company's partnerships. The net gain in 2015 was mainly the result of a lawsuit settlement related to participation rights on some of the Company's mineral acreage in Arkansas.

Interest Expense

Interest expense decreased $205,864 in 2016, as compared to 2015. The decrease was due to a lower outstanding debt balance in 2016.

General and Administrative Costs (G&A)

G&A decreased $199,592 in 2016, as compared to 2015. This decrease was primarily the result of lower legal and technical consulting fees in 2016.

Provision (Benefit) for Income Taxes

The 2016 benefit for income taxes of $7,711,000 was based on a pre-tax loss of $17,997,884, as compared to a provision for income taxes of $4,836,000 in 2015, based on a pre-tax income of $14,157,341. The effective tax rate for 2016 was 43%, compared to an effective tax rate for 2015 of 34%. When a provision for income taxes is recorded, 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 in 2016.

Fiscal Year 2015 Compared to Fiscal Year 2014

Overview

The Company recorded net income of $9,321,341, or $0.56 per share, in 2015, compared to net income of $25,001,462, or $1.49 per share, in 2014. Revenues decreased in 2015 primarily due to lower oil, NGL and natural gas sales, partially offset by increased gains on derivative contracts and increased lease bonuses received.

Expenses increased in 2015 due mainly to higher LOE, DD&A, interest expense and provision for impairment, partially offset by a decrease in production taxes and an increase in other miscellaneous income.

Oil, NGL and Natural Gas Sales

Oil, NGL and natural gas sales decreased $28,312,614, or 34%, for 2015, as compared to 2014. The decrease was due to decreased oil, NGL and natural gas prices of 43%, 44% and 33%, respectively coupled with lower gas volumes of 10%, offset by increased oil and NGL volumes of 31% and 2%, respectively, in 2015.

The oil production volume increase was primarily the result of the Company’s acquisition of producing properties in the Eagle Ford Shale in South Texas in June 2014 and the associated horizontal drilling on that leasehold. To a lesser extent, Woodford Shale drilling in the Anadarko Basin in western and southern Oklahoma and drilling in the Bakken Shale in North Dakota contributed to the increase. The increase in oil production volumes during 2015 was partially offset by naturally declining oil production from the Company’s properties in Oklahoma and the Texas Panhandle.

The NGL production volume increase was primarily the result of Woodford Shale drilling in the Anadarko Basin in western and southern Oklahoma, the Eagle Ford Shale acquisition and subsequent drilling and drilling in the Bakken Shale in North Dakota. The increase in NGL production volumes during 2015 was largely offset by naturally declining NGL production from the Company's properties in Oklahoma and the Texas Panhandle.

The natural gas production volume decrease was largely the result of naturally declining production in the Fayetteville Shale, which was not offset by new production in the play due to significantly reduced drilling activity. Declining production from several of the Company's properties in western Oklahoma and the Texas Panhandle, as well as from the southeastern Oklahoma Woodford, also contributed to the decrease. Lower production volumes were partially offset by production increases in the Anadarko Basin Woodford in western and southern Oklahoma and the Eagle Ford Shale in South Texas.

Production by quarter for 2015 and 2014 was as follows (Mcfe):

	2015	2014
First quarter	3,737,483	3,509,270
Second quarter	3,455,265	3,496,222
Third quarter	3,315,899	3,309,394
Fourth quarter	3,221,086	3,783,123
Total	13,729,733	14,098,009

Lease Bonus and Rentals

Lease bonuses and rentals increased $1,587,067 in 2015. The increase was mainly due to the Company leasing 2,407 net mineral acres in Andrews and Winkler Counties, Texas, for $1.2 million. There were no significant leases of the Company's mineral acreage in 2014.

Gains (Losses) on Derivative Contracts

Gains on derivative contracts increased $13,575,092 in 2015. The increase in gains was mainly due to the oil and natural gas collars and fixed price swaps being more beneficial in 2015, as NYMEX oil and natural gas futures had fallen further below the floor of the collars and the fixed prices of the swaps. As of September 30, 2015, the Company's natural gas costless collar contracts have expiration dates of October and December 2015; the oil costless collar contracts and the oil fixed price swaps have an expiration date of December 2015.

Lease Operating Expenses (LOE)

LOE increased $3,559,616 or 26% in 2015. LOE costs per Mcfe of production increased from $0.99 in 2014 to $1.27 in 2015. The total LOE increase was primarily due to increased field operating costs of $3,598,103 in 2015, compared to 2014. Field operating costs increased mainly due to the acquisition of the Eagle Ford Shale properties and additional wells drilled in late 2014 and during 2015. Field operating costs were $.78 per Mcfe in 2015, compared to $.50 per Mcfe in 2014, a 56% increase. This increase in rate was principally the result of the significant number of oil and NGL rich wells drilled in recent years. These wells have higher lifting costs than our overall well population, which is and has been heavily gas weighted for several years.

The increase in LOE related to field operating costs was partially offset by a decrease in handling fees (primarily gathering, transportation and marketing costs) on natural gas of $38,487 in 2015, as compared to 2014. On a per Mcfe basis, these fees increased $.01 due to increased fees in areas that are currently being drilled. Natural gas sales bear the large majority of the handling fees. Handling fees are charged either as a percent of sales or based on production volumes.

Production Taxes

Production taxes decreased $991,816 or 37% in 2015, as compared to 2014. The decrease in amount was primarily the result of decreased oil, NGL and natural gas sales of $28,312,614 during 2015. Production taxes as a percentage of oil, NGL and natural gas sales decreased slightly from 3.3% in 2014 to 3.1% in 2015. The low overall production tax rate was due to a large proportion of the Company's oil and natural gas revenues coming from horizontally drilled wells, which are eligible for reduced Oklahoma and Arkansas production tax rates.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased $1,924,237 in 2015. DD&A per Mcfe was $1.74 in 2015, compared to $1.55 in 2014. DD&A increased $2,496,240 as the result of a $.19 increase in the DD&A rate. This rate increase was principally due to higher per Mcfe finding costs experienced in oil and liquids rich areas where the Company has added production, as well as much lower oil, NGL and natural gas prices utilized in the reserve calculations during 2015, as compared to 2014, resulting in lower projected remaining reserves on a significant number of wells. An offsetting decrease of $572,003 was due to oil, NGL and natural gas production volumes decreasing 3% collectively in 2015, compared to 2014.

Provision for Impairment

Provision for impairment increased $3,913,115 in 2015, as compared to 2014. During 2015, impairment of $5,009,191 was recorded on 27 fields primarily in Oklahoma, Kansas and Texas. One oil field in Hemphill County, Texas, accounted for $1,846,488 of the impairment due mainly to declining oil prices. During 2014, impairment of $1,096,076 was primarily recorded on 10 small fields in Oklahoma and Texas.

Loss (Gain) on Asset Sales and Other

Loss (gain) on asset sales and other was a net gain of $398,994 in 2015, as compared to a net loss of $8,378 in 2014. The net gain in 2015 was mainly the result of a lawsuit settlement of approximately $331,000 related to participation rights on some of the Company's mineral acreage in Arkansas. The net loss in 2014 was primarily the result of a loss on the sale of marginal properties partially offset by higher interest income from operators.

Interest Expense

Interest expense increased $1,088,187 in 2015, as compared to 2014. The increase was primarily due to a larger average outstanding debt balance in 2015. The debt was used to purchase the Eagle Ford Shale properties on June 17, 2014.

Provision (Benefit) for Income Taxes

The 2015 provision for income taxes of $4,836,000 was based on a pre-tax income of $14,157,341, as compared to a provision for income taxes of $11,820,000 in 2014, based on a pre-tax income of $36,821,462. The effective tax rate for 2015 was 34%, compared to an effective tax rate for 2014 of 32%. The Company's utilization of excess percentage depletion, which is a permanent tax benefit, decreased the provision for income taxes and reduced the effective tax rate below the statutory rate for both years.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2016, the Company had positive working capital of $2,098,460, as compared to positive working capital of $8,907,437 at September 30, 2015.

Liquidity

Cash and cash equivalents were $471,213 as of September 30, 2016, compared to $603,915 at September 30, 2015, a decrease of $132,702. Cash flows for the 12 months ended September 30 are summarized as follows:

Net cash provided (used) by:

	2016	2015	Change
Operating activities	$ 22,639,151	$ 47,624,914	$(24,985,763)
Investing activities	565,617	(31,642,385)	32,208,002
Financing activities	(23,337,470)	(15,888,369)	(7,449,101)
Increase (decrease) in cash and cash equivalents	$ (132,702)	$ 94,160	$ (226,862)

Operating activities:

Net cash provided by operating activities decreased $24,985,763 during 2016, as compared to 2015, the result of the following:

- Receipts of oil, NGL and natural gas sales (net of production taxes and gathering, transportation and marketing costs) and other decreased $27,789,295.
- Increased receipts from leasing of fee mineral acreage of $5,995,534.
- Decreased income tax payments of $979,962.
- Decreased net receipts on derivative contracts of $6,960,904.

- Decreased payments for interest expense of $193,411.

- Decreased payments for G&A and other expense of $367,436.

- Decreased payments for field operating expenses of $2,228,093.

Investing activities:

Net cash used in investing activities decreased $32,208,002 during 2016, as compared to 2015, due to:

- Lower drilling and completion activity during 2016 decreased capital expenditures by $26,814,390.

- Higher proceeds from sale of assets of $4,501,726.

Financing activities:

Net cash used in financing activities increased $7,449,101 during 2016, as compared to 2015, the result of the following:

- During 2016, net borrowings decreased $20,500,000. During 2015, net borrowings decreased $13,000,000.

Capital Resources

Capital expenditures to drill and complete wells decreased $26,814,390 (87%) in 2016, as compared to 2015. In the Eagle Ford Shale oil play in South Texas and in the Arkansas Fayetteville Shale natural gas play there was very limited drilling activity on the Company's acreage in 2016. The Company received 58 well proposals in fiscal 2016, and working interest participation decisions were as follows: 20 wells met the Company's participation criteria and elections were made to participate; 34 wells did not meet participation criteria with no participation elected; and 4 wells did not meet participation criteria, but election was made to participate with only one acre, in order to receive well information. The drilling activity decrease resulted in the 87% decline in capital expenditures.

Drilling began in August 2016 and continues into fiscal 2017 on the eight wells proposed on Company owned mineral acres in the southeast Oklahoma Woodford Shale play. The Company agreed to participate in these wells with an average 20% working interest, which combined with the royalty interest to be received on the portion of the minerals leased, will average net revenue interests of 27.4%. The Company's capital obligation to drill and complete these eight wells is approximately $7.4 million. Completion of all eight wells is projected to be in the second quarter of fiscal 2017.

Panhandle recently received notice from an operator in the core of the STACK/CANA play of their plans to drill six wells in one unit beginning in December 2016. Panhandle has elected to participate with 17.5% working interest and a 16.25% net revenue interest in these six

Woodford Shale wells. The operator plans to drill the wells with two rigs and projects will begin producing early in the third fiscal quarter of 2017.

Pad drilling is scheduled to resume on our Eagle Ford leasehold acreage in our second fiscal quarter of 2017. The operator plans to move in one rig and drill a ten-well program. This activity should occur over a roughly six to seven month period. Panhandle will have 16% working interest in six of the wells that are entirely located on our acreage and approximately 8.2% working interest in the other four that are roughly half on our acreage.

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

Oil, NGL and natural gas production volumes decreased 16% on an Mcfe basis during 2016, as compared to 2015. Low drilling activity during 2016 resulted in new production coming on line falling considerably short of replacing the natural decline of existing wells.

Oil production decreased 20%, primarily the result of the production decline in the Eagle Ford Shale, which was not offset by new production in the play due to significantly reduced drilling activity. Declining production from various fields in western Oklahoma, the Texas Panhandle and the Northern Oklahoma Mississippian also contributed to the decrease, to a lesser extent.

NGL production decreased 19%, largely the result of production decline in the Anadarko Woodford Shale in western and central Oklahoma and the Anadarko Basin Granite Wash in western Oklahoma and the Texas Panhandle.

Natural gas production decreased 15%, principally due to declining production in the Fayetteville Shale. To a lesser extent, declining production from the Anadarko Basin Granite Wash and the southeastern Oklahoma Woodford Shale also contributed to the decrease.

As of September 30, 2016, the Company owned an average 3.5% net revenue interest in 45 wells that were drilling or testing. Of these 45 wells, only four of the southeast Oklahoma Woodford Shale wells are included as the other four had not yet begun drilling.

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 2017 capital expenditures for drilling and completion projects difficult to forecast.

The Company received lease bonus payments during 2016 totaling approximately $8 million. The Company has also received $4.5 million during 2016 from the sale of properties. Cash provided by these and other operating activities allowed the Company to fund all overhead costs, capital expenditures, treasury stock purchases and dividend payments, while also reducing the Company's outstanding borrowings on the credit facility by $20.5 million during 2016. 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 1 to the financial statements included in Exhibit 99.3 attached to this Form 8-K 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:

	Twelve months ended 9/30/2016
Cash provided by operating activities	$ 22,639,151
Cash used for (provided by):	
Capital expenditures - drilling and completion of wells	3,986,235
Quarterly dividends of $.04 per share	2,677,305
Treasury stock purchases	117,165
Net payments (borrowings) on credit facility	20,500,000
Proceeds from sales of assets	(4,501,726)
Other investing activities	(7,126)
Net cash used	22,771,853
Net increase (decrease) in cash	$ (132,702)

Outstanding borrowings on the credit facility at September 30, 2016, were $44,500,000.

Looking forward, the Company intends to fund overhead costs, capital additions related to the drilling and completion of wells, treasury stock purchases, if any, and dividend payments primarily 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 ($35,500,000 at September 30, 2016) under its revolving credit facility and was in compliance with its debt covenants (current ratio, debt to trailing 12 month EBITDA, as defined, and dividends as a percent of operating cash flow). Non-cash expenses (such as impairment) are excluded from the EBITDA calculation. The debt covenants require a maximum ratio of the Company’s debt to EBITDA of 4:1. As of September 30, 2016, the debt to EBITDA ratio was 1.82:1.

The borrowing base under the credit facility was redetermined in December 2016 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.

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

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a credit facility with a group of banks headed by Bank of Oklahoma (BOK) consisting of a revolving loan of $200,000,000, which is subject to a semi-annual borrowing base determination. The current borrowing base is $80,000,000 and is secured by certain of the Company's properties with a carrying value of $166,720,207 at September 30, 2016. The revolving loan matures on November 30, 2018. Borrowings under the revolving loan are due at maturity. The revolving loan bears interest at the BOK prime rate plus a range of 0.375% to 1.125%, or 30 day LIBOR plus a range of 1.875% to 2.625% annually. At September 30, 2016, the effective rate was 2.73%. The election of BOK prime or LIBOR is at the Company's discretion. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of the Company's oil and natural gas properties is advanced.

Determinations of the borrowing base are made semi-annually, whenever BOK believes there has been a material change in the value of the Company's oil and natural gas properties or upon reasonable request by the Company. The loan agreement contains customary covenants, which, among other things, require periodic financial and reserve reporting and limit the Company's incurrence of indebtedness, liens, dividends and acquisitions of treasury stock and require the Company to maintain certain financial ratios. At September 30, 2016, the Company was in compliance with these covenants and projects compliance during 2017.

The table below summarizes the Company's contractual obligations and commitments as of September 30, 2016:

	Payments due by period				
Contractual Obligations and Commitments	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$44,500,000	$ -	$44,500,000	$ -	$ -
Building lease	$ 743,686	$204,089	$ 416,938	$ 122,659	$ -

The Company's building lease is accounted for as an operating lease and therefore the leased asset and associated liabilities of future rent payments are not included on the Company's balance sheets.

At September 30, 2016, the Company's derivative contracts were in a net liability position of $428,271. The ultimate settlement amounts of the derivative contracts are unknown because they are subject to continuing market risk. Please read Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 1 to the financial statements included in Exhibit 99.3 attached to this Form 8-K for additional information regarding the derivative contracts.

As of September 30, 2016, the Company's estimate for asset retirement obligations was $2,958,048. Asset retirement obligations represent the Company's share of the future expenditures to plug and abandon the wells in which the Company owns a working interest at the end of their economic lives. These amounts were not included in the schedule above due to the uncertainty of timing of the obligations. Please read Note 1 to the financial statements included in Exhibit 99.3 attached to this Form 8-K for additional information regarding the Company's asset retirement obligations.

CRITICAL ACCOUNTING POLICIES

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by the Company generally do not change the Company's reported cash flows or liquidity. Existing rules must be interpreted and judgments made on how the specifics of a given rule apply to the Company.

The more significant reporting areas impacted by management's judgments and estimates are: crude oil, NGL and natural gas reserve estimation; derivative contracts; impairment of assets; oil, NGL and natural gas sales revenue accruals; refundable production taxes and provision for income taxes. 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. Actual results could differ from the estimates as additional information becomes known. The oil, NGL and natural gas sales revenue accrual is particularly subject to estimate inaccuracies due to the Company's status as a non-operator on all of its properties. As such, production and price information obtained from well operators is substantially delayed. This causes the estimation of recent production and prices used in the oil, NGL and natural gas revenue accrual to be subject to future change.

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. These estimates affect the unaudited standardized measure disclosures included in Note 11 to the financial statements included in Exhibit 99.3 attached to this Form 8-K as well as DD&A and impairment calculations. Changes in crude oil, NGL and natural gas reserve estimates affect the Company's calculation of DD&A, asset retirement obligations 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, geological and geophysical information. Between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing prices which are updated through the current period. In accordance with the SEC rules, the reserve estimates were based on average individual product prices during the 12-month period prior to September 30 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. Based on the Company's 2016 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $2,448,757 annual change in DD&A expense. Crude oil, NGL and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. 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.

Successful Efforts Method of Accounting

The Company has elected to utilize the successful efforts method of accounting for its oil and natural gas exploration and development activities. This means exploration expenses, including geological and geophysical costs, non-producing lease impairment, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized by property using the unit-of-production method (the ratio of oil, NGL and natural gas volumes produced to total proved or proved developed reserves is used to amortize the remaining asset basis on each producing property) as oil, NGL and natural gas is produced. The Company's exploratory wells are all on-shore and primarily located in the Mid-Continent area. Generally, expenditures on exploratory wells comprise less than 10% of the Company's total expenditures for oil and natural gas properties. This accounting method may yield significantly different operating results than the full cost method.

Derivative Contracts

The Company has entered into oil and natural gas costless collar contracts and oil and natural gas fixed swap contracts. These instruments are intended to reduce the Company's exposure to short-term fluctuations in the price of oil and natural gas. 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. Fixed swap contracts set a fixed price and provide for 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. These contracts cover only a portion of the Company's oil and natural gas production and provide only partial price protection against declines in oil and natural gas prices. These derivative instruments expose the Company to risk of financial loss and may 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 Company is required to recognize all derivative instruments as either assets or liabilities in the balance sheet at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. At September 30, 2016, the Company had no derivative contracts designated as cash flow hedges, and therefore, changes in the fair value of derivatives are reflected in earnings.

Impairment of Assets

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 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; economic and regulatory climates and other factors. The Company estimates future net cash flows on its oil and natural gas properties utilizing differentially adjusted forward pricing curves for oil, NGL and natural gas and a discount rate in line with the discount rate we believe is most commonly used by market participants (10% for all periods presented). 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. A further reduction in oil, NGL and natural gas prices (which are reviewed quarterly) or a decline in reserve volumes (which are re-evaluated semi-annually) would likely lead to additional impairment that may be material to the Company. Should product price expectations decline below levels seen at September 30, 2016, in future periods, impairment charges significantly greater than the Company has incurred in prior periods could result. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded.

Non-producing oil and natural gas leases are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties' costs, which the Company believes will not be transferred to proved properties over the remaining lives of the leases. Impairment loss is charged to exploration costs when recognized. As of September 30, 2016, the remaining carrying cost of non-producing oil and natural gas leases was $153,884.

Oil, NGL and Natural Gas Sales Revenue Accrual

The Company does not operate its oil and natural gas properties and, therefore, receives actual oil, NGL and natural gas sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, on wells with greater significance to the Company, the most current available production data is gathered from the appropriate operators, and oil, NGL and natural gas index prices local to each well are used to estimate the accrual of revenue on these wells. Obtaining timely production data on all other wells from the operators is not feasible; therefore, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The oil, NGL and natural gas sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, NGL and natural gas. These variables could lead to an over or under accrual of oil, NGL and natural gas sales at the end of any particular quarter. Based on past history, the Company's estimated accruals have been materially accurate.

Income Taxes

The estimation of the amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations, as well as the completion of complex calculations, including the determination of the Company's percentage depletion deduction, if any. To calculate the exact excess percentage depletion allowance, a well-by-well calculation is, and can only be, performed at the end of each fiscal year. During interim periods, an estimate is made taking into account historical data and current pricing. The Company has certain state net operating loss carry forwards (NOLs) that are recognized as tax assets when assessed as more likely than not to be utilized before their expiration dates. Criteria such as expiration dates, future excess state depletion and reversing taxable temporary differences are evaluated to determine whether the NOLs are more likely than not to be utilized before they expire. If any NOLs are determined to no longer be more likely than not to be utilized, then a valuation allowance is recognized to reduce the tax benefit of such NOLs. As of September 30, 2016, the Company had no valuation allowances on NOLs. Although the Company's management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax matters.

The above description of the Company's critical accounting policies is not intended to be an all-inclusive discussion of the uncertainties considered and estimates made by management in applying generally accepted accounting principles and policies. Results may vary significantly if different policies were used or required and if new or different information becomes known to management.

ITEM 7A 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 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 (see below), the price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $828,438 for operating revenue based on the Company's prior year natural gas volumes. The price sensitivity in 2017 for each $1.00 per barrel change in wellhead oil is approximately $364,252 for operating revenue based on the Company's prior year oil volumes.

Commodity Price Risk

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in natural gas and oil 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 natural gas and oil 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 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 $146,000. 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 $247,000. 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 $51,000. See Note 1 to the financial statements included in Exhibit 99.3 attached to this Form 8-K for additional information regarding the derivative contracts.

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 facility. 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 September 30, 2016, the Company had $44,500,000 outstanding under this facility and the effective interest rate was 2.73%. At this point, the Company does not believe that its liquidity has been materially affected by the debt market uncertainties noted in the last few years and the Company does not believe that its liquidity will be impacted in the near future.

EXHIBIT 99.3

This exhibit does not reflect events occurring after the filing date of Panhandle Oil and Gas Inc.’s Annual Report on Form 10-K for the year ended September 30, 2016, other than to give effect to the reclassification of our proceeds from leasing fee mineral acreage on the Statements of Cash Flows and deferred income taxes on the Balance Sheets and does not modify or update the disclosures therein in anyway, other than described above.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management’s Annual Report on Internal Control Over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934 (the “Exchange Act”) as a process designed by, or under the supervision of, the Company’s principal executive and principal financial officers and effected by the Company’s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles in the United States, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The Company’s management assessed the effectiveness of the Company’s internal control over financial reporting as of September 30, 2016. In making this assessment, the Company’s management used the criteria set forth in *Internal Control – Integrated Framework* (as updated in 2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, management has concluded that, as of September 30, 2016, the Company’s internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. This report appears on the following page.

Report of Independent Registered Public Accounting Firm
on Internal Control Over Financial Reporting

The Board of Directors and Stockholders of
Panhandle Oil and Gas Inc.

We have audited Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Panhandle Oil and Gas Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Panhandle Oil and Gas Inc. maintained, in all material respects, effective internal control over financial reporting as of September 30, 2016, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the balance sheets of Panhandle Oil and Gas Inc. as of September 30, 2016 and 2015, and the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2016 and our report dated December 12, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 12, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Panhandle Oil and Gas Inc.

We have audited the accompanying balance sheets of Panhandle Oil and Gas Inc. (the Company) as of September 30, 2016 and 2015, and the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Panhandle Oil and Gas Inc. at September 30, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2016, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated December 12, 2016, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 12, 2016, except for the impact of the
matters discussed in Note 1 pertaining to the
adoption of ASU 2015-17 and ASU 2016-15, as to
which the date is November 6, 2017

Panhandle Oil and Gas Inc.
Balance Sheets

	September 30, 2016	September 30, 2015
Assets		
Current Assets:		
Cash and cash equivalents	$ 471,213	$ 603,915
Oil, NGL and natural gas sales receivables (net of allowance for uncollectable accounts)	5,287,229	7,895,591
Refundable income taxes	83,874	345,897
Refundable production taxes	-	476,001
Derivative contracts, net	-	4,210,764
Other	419,037	252,016
Total current assets	6,261,353	13,784,184
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	434,469,093	441,141,337
Non-producing oil and natural gas properties	7,574,649	8,293,997
Furniture and fixtures	1,069,658	1,393,559
	443,113,400	450,828,893
Less accumulated depreciation, depletion and amortization	(251,707,749)	(228,036,803)
Net properties and equipment	191,405,651	222,792,090
Investments	157,322	2,248,999
Total assets	$ 197,824,326	$ 238,825,273

(Continued on next page)

See accompanying notes.

Panhandle Oil and Gas Inc.
Balance Sheets

	September 30, 2016	September 30, 2015
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 2,351,623	$ 2,028,746
Derivative contracts, net	403,612	-
Accrued liabilities and other	1,718,558	1,330,901
Total current liabilities	4,473,793	3,359,647
Long-term debt	44,500,000	65,000,000
Deferred income taxes	30,676,007	40,636,007
Asset retirement obligations	2,958,048	2,824,944
Derivative contracts, net	24,659	-
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized; 16,863,004 issued at September 30, 2016 and 2015	280,938	280,938
Capital in excess of par value	3,191,056	2,993,119
Deferred directors' compensation	3,403,213	3,084,289
Retained earnings	112,482,284	125,446,473
	119,357,491	131,804,819
Treasury stock, at cost; 262,708 shares at September 30, 2016, and 302,623 shares at September 30, 2015	(4,165,672)	(4,800,144)
Total stockholders' equity	115,191,819	127,004,675
Total liabilities and stockholders' equity	$197,824,326	$238,825,273

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Operations

	Year ended September 30,		
	2016	**2015**	**2014**
Revenues:			
Oil, NGL and natural gas sales	$ 31,411,353	$54,533,914	$82,846,528
Lease bonuses and rentals	7,735,785	2,010,395	423,328
Gains (losses) on derivative contracts	(86,355)	13,822,506	247,414
Income from partnerships	2,400	515,278	893,954
	39,063,183	70,882,093	84,411,224
Costs and expenses:			
Lease operating expenses	13,590,089	17,472,408	13,912,792
Production taxes	1,071,632	1,702,302	2,694,118
Exploration costs	31,589	48,404	86,017
Depreciation, depletion and amortization	24,487,565	23,821,139	21,896,902
Provision for impairment	12,001,271	5,009,191	1,096,076
Loss (gain) on asset sales and other	(2,624,642)	(398,994)	8,378
Interest expense	1,344,619	1,550,483	462,296
General and administrative	7,139,728	7,339,320	7,433,183
Bad debt expense (recovery)	19,216	180,499	-
	57,061,067	56,724,752	47,589,762
Income (loss) before provision (benefit) for income taxes	(17,997,884)	14,157,341	36,821,462
Provision (benefit) for income taxes	(7,711,000)	4,836,000	11,820,000
Net income (loss)	$(10,286,884)	$ 9,321,341	$25,001,462
Basic and diluted earnings (loss) per common share	$ (0.61)	$ 0.56	$ 1.49

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Stockholders' Equity

	Class A voting Common Stock Shares	Class A voting Common Stock Amount	Capital in Excess of Par Value	Deferred Directors' Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2013	16,863,004	$280,938	$2,447,424	$ 2,756,526	$ 96,454,449	(400,496)	$(6,283,851)	$ 95,655,486
Purchase of treasury stock	-	-	-	-	-	(7,444)	(122,044)	(122,044)
Issuance of treasury shares to ESOP	-	-	161,363	-	-	11,428	179,762	341,125
Restricted stock awards	-	-	659,320	-	-	-	-	659,320
Distribution of restricted stock to officers and directors	-	-	(406,764)	-	-	24,148	367,966	(38,798)
Common shares to be issued to directors for services	-	-	-	353,825	-	-	-	353,825
Dividends declared ($.16 per share)	-	-	-	-	(2,661,723)	-	-	(2,661,723)
Net income (loss)	-	-	-	-	25,001,462	-	-	25,001,462
Balances at September 30, 2014	16,863,004	$280,938	$2,861,343	$ 3,110,351	$118,794,188	(372,364)	$(5,858,167)	$119,188,653
Purchase of treasury stock	-	-	-	-	-	(12,719)	(242,313)	(242,313)
Issuance of treasury shares to ESOP	-	-	3,437	-	-	11,455	181,676	185,113
Restricted stock awards	-	-	895,127	-	-	-	-	895,127
Distribution of restricted stock to officers and directors	-	-	(782,832)	-	-	48,633	766,301	(16,531)
Distribution of deferred directors' compensation	-	-	16,044	(328,415)	-	22,372	352,359	39,988
Common shares to be issued to directors for services	-	-	-	302,353	-	-	-	302,353
Dividends declared ($.16 per share)	-	-	-	-	(2,669,056)	-	-	(2,669,056)
Net income (loss)	-	-	-	-	9,321,341	-	-	9,321,341
Balances at September 30, 2015	16,863,004	$280,938	$2,993,119	$ 3,084,289	$125,446,473	(302,623)	$(4,800,144)	$127,004,675
Purchase of treasury stock	-	-	-	-	-	(7,477)	(117,165)	(117,165)
Issuance of treasury shares to ESOP	-	-	19,068	-	-	11,418	181,090	200,158
Restricted stock awards	-	-	781,479	-	-	-	-	781,479
Distribution of restricted stock to officers and directors	-	-	(601,779)	-	-	35,257	559,175	(42,604)
Distribution of deferred directors' compensation	-	-	(831)	(10,541)	-	717	11,372	-
Common shares to be issued to directors for services	-	-	-	329,465	-	-	-	329,465
Dividends declared ($.16 per share)	-	-	-	-	(2,677,305)	-	-	(2,677,305)
Net income (loss)	-	-	-	-	(10,286,884)	-	-	(10,286,884)
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

See accompanying notes.

Panhandle Oil and Gas Inc.
Statements of Cash Flows

	Year ended September 30,		
	2016	2015	2014
Operating Activities			
Net income (loss)	$(10,286,884)	$ 9,321,341	$25,001,462
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	24,487,565	23,821,139	21,896,902
Impairment	12,001,271	5,009,191	1,096,076
Provision for deferred income taxes	(9,960,000)	2,672,000	6,610,000
Exploration costs	31,589	48,404	86,017
Gain from leasing fee mineral acreage	(7,732,023)	(2,007,993)	(422,818)
Proceeds from leasing fee mineral acreage	8,049,434	2,053,900	477,144
Net (gain) loss on sales of assets	(2,688,408)	-	149,062
Income from partnerships	(2,400)	(515,278)	(893,954)
Distributions received from partnerships	33,201	736,280	1,129,324
Common stock contributed to ESOP	200,158	185,113	341,125
Common stock (unissued) to Directors' Deferred Compensation Plan	329,465	302,353	353,825
Restricted stock awards	781,479	895,127	659,320
Bad debt expense (recovery)	19,216	180,499	-
Cash provided (used) by changes in assets and liabilities:			
Oil, NGL and natural gas sales receivables	2,589,146	8,151,379	(2,506,708)
Fair value of derivative contracts	4,639,035	(2,308,922)	(1,476,644)
Refundable income taxes	262,023	(345,897)	-
Refundable production taxes	476,001	149,995	576,537
Other current assets	(167,021)	102,812	(224,830)
Accounts payable	(811,749)	(343,186)	252,860
Income taxes payable	-	(523,843)	(284,149)
Accrued liabilities	388,053	40,500	279,195
Total adjustments	32,926,035	38,303,573	28,098,284
Net cash provided by operating activities	22,639,151	47,624,914	53,099,746

(Continued on next page)

Panhandle Oil and Gas Inc.
Statements of Cash Flows (continued)

	Year ended September 30,		
	2016	**2015**	**2014**
Investing Activities			
Capital expenditures, including dry hole costs	$ (3,986,235)	$(30,800,625)	$ (38,612,788)
Acquisition of working interest properties	-	(308,180)	(83,253,952)
Acquisition of minerals and overrides	-	-	(56,250)
Investments in partnerships	50,126	(533,580)	(597,149)
Proceeds from sales of assets	4,501,726	-	92,000
Net cash used in investing activities	565,617	(31,642,385)	(122,428,139)
Financing Activities			
Borrowings under debt agreement	12,339,101	25,833,116	99,846,333
Payments of loan principal	(32,839,101)	(38,833,116)	(30,108,589)
Purchases of treasury stock	(117,165)	(242,313)	(122,044)
Payments of dividends	(2,677,305)	(2,669,056)	(2,661,723)
Excess tax benefit on stock-based compensation	(43,000)	23,000	17,000
Net cash provided by (used in) financing activities	(23,337,470)	(15,888,369)	66,970,977
Increase (decrease) in cash and cash equivalents	(132,702)	94,160	(2,357,416)
Cash and cash equivalents at beginning of year	603,915	509,755	2,867,171
Cash and cash equivalents at end of year	$ 471,213	$ 603,915	$ 509,755
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$ 1,365,474	$ 1,558,885	$ 380,451
Income taxes paid, net of refunds received	$ 2,029,977	$ 3,009,939	$ 5,477,147
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$ 14,095	$ 70,529	$ 225,453
Gross additions to properties and equipment	$ 5,118,733	$ 26,183,115	$ 120,284,639
Net (increase) decrease in accounts payable for properties and equipment additions	(1,132,498)	4,925,690	1,638,351
Capital expenditures, including dry hole costs	$ 3,986,235	$ 31,108,805	$ 121,922,990

See accompanying notes.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Through management of its fee mineral and leasehold acreage, the Company's principal line of business is to explore for, develop, acquire, produce and sell oil, NGL and natural gas. Panhandle's mineral and leasehold properties and other oil and natural gas interests are all located in the contiguous United States, primarily in Arkansas, New Mexico, North Dakota, Oklahoma and Texas, with properties located in several other states. The Company also owns immaterial international overriding royalty interests. The Company's oil, NGL and natural gas production is from interests in 6,233 wells located principally in Arkansas, Oklahoma and Texas. The Company is not the operator of any wells. Approximately 51% of oil, NGL and natural gas revenues were derived from the sale of natural gas in 2016. Approximately 72% of the Company's total sales volumes in 2016 were derived from natural gas. Substantially all the Company's oil, NGL and natural gas production is sold through the operators of the wells. From time to time, the Company sells certain non-material, non-core or small-interest oil and natural gas properties in the normal course of business.

Use of Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Of these estimates and assumptions, management considers the estimation of crude oil, NGL and natural gas reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. On an annual basis, with a semi-annual update, the Company's Independent Consulting Petroleum Engineer, with assistance from the Company, 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, geological and geophysical information. For DD&A purposes, and as required by the guidelines and definitions established by the SEC, the reserve estimates were based on average individual product prices during the 12-month period prior to September 30, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. For impairment purposes, projected future crude oil, NGL and natural gas prices as estimated by management are used. Crude oil, NGL and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Management uses projected future crude oil, NGL and natural gas pricing assumptions to prepare estimates of crude oil, NGL and natural gas reserves used in formulating management’s overall operating decisions.

The Company does not operate its oil and natural gas properties and, therefore, receives actual oil, NGL and natural gas sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, on wells with greater significance to the Company, the most current available production data is gathered from the appropriate operators, and oil, NGL and natural gas index prices local to each well are used to estimate the accrual of revenue on these wells. Timely obtaining production data on all other wells from the operators is not feasible; therefore, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The oil, NGL and natural gas sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, NGL and natural gas. These variables could lead to an over or under accrual of oil, NGL and natural gas sales at the end of any particular quarter. Based on past history, the Company’s estimated accrual has been materially accurate.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in short-term investments with original maturities of three months or less.

Oil, NGL and Natural Gas Sales and Natural Gas Imbalances

The Company sells oil, NGL and natural gas to various customers, recognizing revenues as oil, NGL and natural gas is produced and sold. Charges for compression, marketing, gathering and transportation of natural gas are included in lease operating expenses.

The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has underproduced or overproduced its ownership percentage in a property. Under this method, a receivable or liability is recorded to the extent that an underproduced or overproduced position in a well cannot be recouped through the production of remaining reserves. At September 30, 2016 and 2015, the Company had no material natural gas imbalances.

Accounts Receivable and Concentration of Credit Risk

Substantially all of the Company’s accounts receivable are due from purchasers of oil, NGL and natural gas or operators of the oil and natural gas properties. Oil, NGL and natural gas sales receivables are generally unsecured. This industry concentration has the potential to impact our overall exposure to credit risk, in that the purchasers of our oil, NGL and natural gas and the operators of the properties in which we have an interest may be similarly affected by changes in economic, industry or other conditions. During 2016 and 2015, the Company recognized a reserve for bad debt expense of $19,216 and $180,499, respectively.

Oil and Natural Gas Producing Activities

The Company follows the successful efforts method of accounting for oil and natural gas producing activities. Intangible drilling and other costs of successful wells and development dry holes are capitalized and amortized. The costs of exploratory wells are initially capitalized, but charged against income, if and when the well does not commercially produce. Oil and natural gas mineral and leasehold costs are capitalized when incurred.

Non-producing oil and natural gas leases are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties' costs, which the Company believes will not be transferred to proved properties over the remaining lives of the leases. Impairment loss is charged to exploration costs when recognized. As of September 30, 2016, the remaining carrying cost of non-producing oil and natural gas leases was $153,884.

It is common business practice in the petroleum industry to prepay drilling costs before spudding a well. The Company frequently fulfills these prepayment requirements with cash payments, but at times will utilize letters of credit to meet these obligations. As of September 30, 2016, the Company had no outstanding letters of credit.

Leasing of Mineral Rights

When the Company leases its mineral acreage to a third-party company, it retains a royalty interest in any future revenues from the production and sale of oil, NGL or natural gas, and often receives an up-front, non-refundable, cash payment (lease bonus) in addition to the retained royalty interest. A royalty interest does not bear any portion of the cost of drilling, completing or operating a well; these costs are borne by the working interest owners. The Company sometimes leases only a portion of its mineral acres in a tract and retains the right to participate as a working interest owner with the remainder.

The Company recognizes revenue from mineral lease bonus payments when it has received an executed lease agreement with a third-party company transferring the rights to explore for and produce any oil or natural gas they may find within the term of the lease, the payment has been collected, and the Company has no obligation to refund the payment. The Company accounts for its lease bonuses 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.

Derivatives

The Company has entered into 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. 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. 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. These contracts cover only a portion of the Company's oil and natural gas production and provide only partial price protection against declines in oil and natural gas prices. These derivative instruments expose the Company to risk of financial loss and may 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 September 30, 2015

Contract period	Production volume covered per month	Index	Contract price
Natural gas costless collars			
January - December 2015	100,000 Mmbtu	NYMEX Henry Hub	\$3.50 floor / \$4.10 ceiling
January - December 2015	70,000 Mmbtu	NYMEX Henry Hub	\$3.25 floor / \$4.00 ceiling
April - October 2015	50,000 Mmbtu	NYMEX Henry Hub	\$3.50 floor / \$4.00 ceiling
May - October 2015	70,000 Mmbtu	NYMEX Henry Hub	\$3.50 floor / \$3.95 ceiling
Oil costless collars			
July - December 2015	10,000 Bbls	NYMEX WTI	\$80.00 floor / \$86.50 ceiling
Oil fixed price swaps			
April - December 2015	5,000 Bbls	NYMEX WTI	\$94.56
July - December 2015	7,000 Bbls	NYMEX WTI	\$93.91

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 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 liability of $428,271 as of September 30, 2016, and a net asset of $4,210,764 as of September 30, 2015. Realized and unrealized gains and (losses) are recorded in gains (losses) on derivative contracts on the Company’s Statement of Operations.

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 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 Balance Sheets at September 30, 2016, and September 30, 2015. The Company has offset all amounts subject to master netting agreements in the Company's Balance Sheets at September 30, 2016, and September 30, 2015.

	9/30/2016 Fair Value (a) Commodity Contracts				9/30/2015 Fair Value (a) Commodity Contracts
	Current Assets	Current Liabilities	Non-Current Assets	Non-Current Liabilities	Current Assets
Gross amounts recognized	$ 68,235	$ 471,847	$ 4,759	$ 29,418	$ 4,210,764
Offsetting adjustments	(68,235)	(68,235)	(4,759)	(4,759)	-
Net presentation on Balance Sheets	$ -	403,612	$ -	24,659	$ 4,210,764

(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 only if the impact is deemed material. The impact of credit risk was immaterial for all periods presented.

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.

	Fair Value Measurement at September 30, 2016			
	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	$ -	$ (111,613)	$ -	$(111,613)
Derivative Contracts - Collars	$ -	$ -	$ (316,658)	$(316,658)

	Fair Value Measurement at September 30, 2015			
	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	$ -	$2,319,515	$ -	$2,319,515
Derivative Contracts - Collars	$ -	$ -	$ 1,891,249	$1,891,249

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 forward prices and 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 Assets (Liabilities) September 30, 2016
Oil Collars	Oil price volatility curve	0% - 25.87%	15.06%	$ (99,005)
Natural Gas Collars	Natural gas price volatility curve	0% - 32.76%	22.50%	$ (217,653)

A reconciliation of the Company's derivative contracts classified as Level 3 measurements is presented below.

	Derivatives
Net Asset (Liability) Balance of Level 3 as of October 1, 2015	$ 1,891,249
Total gains or (losses):	
Included in earnings	(4,200,367)
Included in other comprehensive income (loss)	-
Purchases, issuances and settlements	1,992,460
Transfers in and out of Level 3	-
Net Asset (Liability) Balance of Level 3 as of September 30, 2016	$ (316,658)

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.

	Year Ended September 30,			
	2016		2015	
	Fair Value	Impairment	Fair Value	Impairment
Producing Properties (a)	$9,877,905	$12,001,271	$4,897,269	$ 5,009,191

(a) At the end of each quarter, the Company assessed the carrying value of its producing properties for impairment. This assessment utilized estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of future oil, NGL and natural gas prices using a forward NYMEX curve adjusted for projected inflation, 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 September 30, 2016, and September 30, 2015, the fair value of financial instruments approximated their carrying amounts. Financial instruments include long-term debt, which 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 relating to nonperformance risk for the debt agreements were considered necessary.

Depreciation, Depletion, Amortization and Impairment

Depreciation, depletion and amortization of the costs of producing oil and natural gas properties are generally computed using the unit-of-production method primarily on an individual property basis using proved or proved developed reserves, as applicable, as estimated by the Company’s Independent Consulting Petroleum Engineer. The Company’s capitalized costs of drilling and equipping all development wells, and those exploratory wells that have found proved reserves, are amortized on a unit-of-production basis over the remaining life of associated proved developed reserves. Lease costs are amortized on a unit-of-production basis over the remaining life of associated total proved reserves. Depreciation of furniture and fixtures is computed using the straight-line method over estimated productive lives of five to eight years.

Non-producing oil and natural gas properties include non-producing minerals, which had a net book value of $3,349,567 and $4,016,465 at September 30, 2016 and 2015, respectively, consisting of perpetual ownership of mineral interests in several states, with 91% of the acreage in Arkansas, New Mexico, North Dakota, Oklahoma and Texas. As mentioned, these mineral rights are perpetual and have been accumulated over the 90-year life of the Company. There are approximately 198,489 net acres of non-producing minerals in more than 6,442 tracts owned by the Company. An average tract contains approximately 29 acres, and the average cost per acre is $40. Since inception, the Company has continually generated an interest in several thousand oil and natural gas wells using its ownership of the fee mineral acres as an ownership basis. There continues to be significant drilling and leasing activity each year on these mineral interests. Non-producing minerals are being amortized straight-line over a 33-year period. These assets are considered a long-term investment by the Company, as they do not expire (as do oil and natural gas leases). Given the above, management concluded that a long-term amortization was appropriate and that 33 years, based on past history and experience, was an appropriate period. Due to the fact that the minerals consist of a large number of properties, whose costs are not individually significant, and because virtually all are in the Company’s core operating areas, the minerals are being amortized on an aggregate basis.

The Company recognizes impairment losses for long-lived assets when indicators of impairment are present and the undiscounted cash flows are not sufficient to recover the assets’ carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted cash flow as estimated by the Company. The Company's estimate of fair value of its oil and natural gas properties at September 30, 2016, is based on the best information available as of that date, including estimates of forward oil, NGL and natural gas prices and costs. The Company’s oil and natural gas properties were reviewed for impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $12,001,271, $5,009,191 and $1,096,076 for 2016, 2015 and 2014, respectively. A further 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. Should product price expectations decline in future periods below levels seen at September 30, 2016, impairment charges significantly greater than the Company has incurred in prior periods could result.

Capitalized Interest

During 2016, 2015 and 2014, interest of $24,929, $148,493 and $172,499, respectively, was included in the Company's capital expenditures. Interest of $1,344,619, $1,550,483 and $462,296, respectively, was charged to expense during those periods. Interest is capitalized using a weighted average interest rate based on the Company's outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the unit-of-production method.

Investments

Insignificant investments in partnerships and limited liability companies (LLC) that maintain specific ownership accounts for each investor and where the Company holds an interest of 5% or greater, but does not have control of the partnership or LLC, are accounted for using the equity method of accounting.

Asset Retirement Obligations

The Company owns interests in oil and natural gas properties, which may require expenditures to plug and abandon the wells upon the end of their economic lives. The fair value of legal obligations to retire and remove long-lived assets is recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, this cost is capitalized by increasing the carrying amount of the related properties and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties and equipment is depreciated over the useful life of the remaining asset. The Company does not have any assets restricted for the purpose of settling the asset retirement obligations.

The following table shows the activity for the years ended September 30, 2016 and 2015, relating to the Company's asset retirement obligations:

	2016	2015
Asset Retirement Obligations as of beginning of the year	$ 2,824,944	$ 2,638,470
Accretion of Discount	128,722	126,769
Wells Acquired or Drilled	17,338	78,110
Wells Sold or Plugged	(12,956)	(18,405)
Asset Retirement Obligations as of end of the year	$ 2,958,048	$ 2,824,944

Environmental Costs

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays. The Company does not believe the existence of current environmental laws, or interpretations thereof, will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future effects on the Company of new laws or interpretations thereof. Since the Company does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by the well operators, with Panhandle being responsible for its proportionate share of the costs involved. Panhandle carries liability and pollution control insurance. However, all risks are not insured due to the availability and cost of insurance.

Environmental liabilities, which historically have not been material, are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At September 30, 2016 and 2015, there were no such costs accrued.

Earnings (Loss) Per Share of Common Stock

Earnings (loss) per share is calculated using net income (loss) divided by the weighted average number of common shares outstanding, plus unissued, vested directors' deferred compensation shares during the period.

Share-based Compensation

The Company recognizes current compensation costs for its Deferred Compensation Plan for Non-Employee Directors (the "Plan"). Compensation cost is recognized for the requisite directors' fees as earned and unissued stock is recorded to each director's account based on the fair market value of the stock at the date earned. The Plan provides that upon retirement, termination or death of the director or upon a change in control of the Company, the shares accrued under the Plan will be issued to the director.

In accordance with guidance on accounting for employee stock ownership plans, the Company records the fair market value of the stock contributed into its ESOP as expense.

Restricted stock awards to officers provide for cliff vesting at the end of three or five years from the date of the awards. These restricted stock awards can be granted based on service time only (non-performance based) or subject to certain share price performance standards (performance based). Restricted stock awards to the non-employee directors provide for quarterly vesting during the calendar year of the award. The fair value of the awards on the grant date is ratably expensed over the vesting period in accordance with accounting guidance.

Income Taxes

The estimation of amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations, as well as the completion of complex calculations, including the determination of the Company's percentage depletion deduction. Although the Company's management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax regulations. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of the Company's assets and liabilities.

The threshold for recognizing the financial statement effect of a tax position is when it is more likely than not, based on the technical merits, that the position will be sustained by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not to be realized upon ultimate settlement with a taxing authority. The Company files income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, the Company is no longer subject to U.S. federal, state, and local income tax examinations for fiscal years prior to 2013.

The Company includes interest assessed by the taxing authorities in interest expense and penalties related to income taxes in general and administrative expense on its Statements of Operations. For fiscal September 30, 2016, 2015 and 2014, the Company recorded interest and penalties of $12,799, $17 and $0, respectively. The Company does not believe it has any significant uncertain tax positions.

New Accounting Standards

In May 2014, the FASB issued Accounting Standard Update (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 transition method that will be elected.

In April 2015, the FASB issued ASU 2015-03 on the presentation of debt issuance costs. The update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. 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. This update is not expected to have a material impact on our financial statements.

In August 2015, the FASB issued ASU 2015-15 which allows for line-of-credit arrangements to be handled consistently with the presentation of debt issuance costs update 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. This update is not expected to have a material impact on our financial statements.

In November 2015, the FASB issued ASU 2015-17 on the presentation of deferred income tax assets and liabilities. 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; however, the adoption of ASU 2015-17 has been reflected in these re-casted 2016 and 2015 financial statements 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 taxes” in long term liabilities and $1,517,100 as of September 30, 2015 from “Deferred income taxes” in current liabilities to “Deferred income taxes” 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-K have been adjusted to reflect the retroactive adoption of ASU 2015-17.

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 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.

In March 2016, the FASB has 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. Several aspects of the accounting for share-based payment award transactions are simplified, including: (*a*) income tax consequences; (*b*) classification of awards as either equity or liabilities; and (*c*) classification on the statement of cash flows. For public entities, the guidance is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. Early adoption is permitted for any organization in any interim or annual period. We are assessing the potential impact that this update will have on our financial statements.

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. The Company early adopted ASU 2016-15 as of December 31, 2016; however, the adoption of ASU 2016-15 has been reflected in these re-casted 2016, 2015 and 2014 financial statements on a retrospective basis to all prior Statements of Cash Flows presented. As a result of the adoption, the Company reclassified “Proceeds from leasing fee mineral acreage”, which totaled $8,049,434, $2,053,900 and $477,144 for the years ended September 30, 2016, 2015 and 2014, respectively, from Investing Activities to Operating Activities on the 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 Statements of Cash Flows presented throughout this report on Form 10-K have been adjusted to reflect the retroactive adoption of ASU 2016-15.

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 our financial statements upon adoption.

2. COMMITMENTS

The Company leases office space in Oklahoma City, Oklahoma, under the terms of an operating lease expiring in April 2020. Future minimum rental payments under the terms of the lease are $204,089, $206,665, $210,273 and $122,659 in 2017, 2018, 2019 and 2020, respectively. Total rent expense incurred by the Company was $202,083 in 2016, $198,238 in 2015 and $202,134 in 2014.

3. INCOME TAXES

The Company's provision (benefit) for income taxes is detailed as follows:

	2016	2015	2014
Current:			
Federal	$ 2,166,000	$2,053,000	$ 4,996,000
State	83,000	111,000	214,000
	2,249,000	2,164,000	5,210,000
Deferred:			
Federal	(8,597,000)	2,033,000	5,702,000
State	(1,363,000)	639,000	908,000
	(9,960,000)	2,672,000	6,610,000
	$(7,711,000)	$4,836,000	$11,820,000

The difference between the provision (benefit) for income taxes and the amount which would result from the application of the federal statutory rate to income before provision (benefit) for income taxes is analyzed below for the years ended September 30:

	2016	2015	2014
Provision (benefit) for income taxes at statutory rate	$(6,299,259)	$4,955,069	$12,887,512
Percentage depletion	(395,649)	(530,783)	(1,466,456)
State income taxes, net of federal provision (benefit)	(683,800)	487,500	1,018,550
Other	(332,292)	(75,786)	(619,606)
	$(7,711,000)	$4,836,000	$11,820,000

Deferred tax assets and liabilities, resulting from differences between the financial statement carrying amounts and the tax basis of assets and liabilities, consist of the following at September 30:

	2016	2015
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 33,656,415	$ 41,880,691
Derivative contracts	-	1,637,987
	33,656,415	43,518,678
Deferred tax assets:		
State net operating loss carry forwards	259,981	323,536
AMT credit carry forwards	-	164,478
Deferred directors' compensation	1,273,279	1,149,217
Restricted stock expense	494,776	457,934
Derivative contracts	166,597	-
Other	785,775	787,506
	2,980,408	2,882,671
Net deferred tax liabilities	$ 30,676,007	$ 40,636,007

At September 30, 2016, the Company had an income tax benefit of $259,981 related to Oklahoma state income tax net operating loss (OK NOL) carry forwards expiring from 2029 to 2031. There is no valuation allowance for the OK NOL’s as management believes they will be utilized before they expire.

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 $166,720,207 at September 30, 2016. 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 September 30, 2016, the effective interest rate was 2.73%.

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 sole discretion, believe that there has been a material change in the value of the oil and natural gas properties. In December 2016, the borrowing base was redetermined by the banks and was 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) of no less than 1.0 to 1.0 and a funded debt to EBITDA (trailing twelve months as defined) of no more than 4.0 to 1.0. At September 30, 2016, the Company was in compliance with the covenants of the loan agreement and had $35,500,000 of availability under its outstanding credit facility.

5. SHAREHOLDERS' EQUITY

Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan in March 2010, the Board approved purchase of up to $1.5 million of the Company's Common Stock, from time to time, equal to the aggregate number of shares of Common Stock awarded pursuant to the Company's 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 May 2014, the board of directors approved for management to make these purchases of the Company's Common Stock at their discretion. The Board's approval included an initial authorization to purchase up to $1.5 million of Common Stock, with a provision for subsequent authorizations without specific action by the Board. As the amount of Common Stock purchased under any authorization reaches $1.5 million, another $1.5 million is automatically authorized for Common Stock purchases unless the Board determines otherwise. Pursuant to these resolutions adopted by the Board, the purchase of additional $1.5 million increments of the Company's Common Stock became authorized and approved effective March 2011, March 2012, and June 2013. As of September 30, 2016, $4,997,790 had been spent under the current program to purchase 345,208 shares. The shares are held in treasury and are accounted for using the cost method. On September 30 each year, treasury shares contributed to the Company's ESOP on behalf of the ESOP participants were 11,418 in 2016, 11,455 in 2015 and 11,428 in 2014.

6. EARNINGS (LOSS) PER SHARE

The following table sets forth the computation of earnings (loss) per share.

	Year ended September 30,		
	2016	2015	2014
Numerator for basic and diluted earnings (loss) per share:			
Net income (loss)	$(10,286,884)	$ 9,321,341	$25,001,462
Denominator for basic and diluted earnings per share:			
Weighted average shares (including for 2016, 2015 and 2014, unissued, vested directors' shares of 263,057, 246,442 and 255,039, respectively)	16,840,856	16,768,904	16,727,183

7. EMPLOYEE STOCK OWNERSHIP PLAN

The Company's ESOP was established in 1984 and is a tax qualified, defined contribution plan that serves as the Company's sole retirement plan for all its employees. Company contributions are made at the discretion of the Board and, to date, all contributions have been made in shares of Company Common Stock. The Company contributions are allocated to all ESOP participants in proportion to their compensation for the plan year, and 100% vesting occurs after three years of service. Any shares that do not vest are treated as forfeitures and are distributed among other vested employees. For contributions of Common Stock, the Company records as expense the fair market value of the stock contributed. The 323,555 shares of the Company's Common Stock held by the plan as of September 30, 2016, are allocated to individual participant accounts, are included in the weighted average shares outstanding for purposes of earnings-per-share computations and receive dividends.

Contributions to the plan consisted of:

Year	Shares	Amount
2016	11,418	$ 200,158
2015	11,455	$ 185,113
2014	11,428	$ 341,125

8. DEFERRED COMPENSATION PLAN FOR DIRECTORS

Annually, outside directors may elect to be included in the Panhandle Oil and Gas Inc. Deferred Directors' Compensation Plan for Non-Employee Directors (the "Plan"). The Plan 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, and may elect to receive shares, if and when issued, over annual time periods up to ten years. 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 under the Plan be issued to the director. The promise to issue such shares in the future is an unsecured obligation of the Company. As of September 30, 2016, there were 272,564 shares (253,712 shares at September 30, 2015) recorded under the Plan. The deferred balance outstanding at September 30, 2016, under the Plan was $3,403,213 ($3,084,289 at September 30, 2015). Expenses totaling $329,465, $302,353 and $353,825 were charged to the Company's results of operations for the years ended September 30, 2016, 2015 and 2014, respectively, and are included in general and administrative expense in the accompanying Statement of Operations.

9. 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 is designed to provide as much flexibility as possible for future grants of restricted stock so the Company can respond as necessary to provide competitive compensation in order to retain, attract and motivate officers of the Company and to align their interests with those of the Company's shareholders.

In June 2010, the Company began awarding shares of the Company's Common Stock as restricted stock (non-performance based) to certain officers. The restricted stock vests at the end of the vesting period and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the shares was based on the closing price of the shares on their award date and will be recognized as compensation expense ratably over the vesting period. Upon vesting, shares are expected to be issued out of shares held in treasury.

In December 2010, the Company also began awarding shares of the Company's Common Stock, subject to certain share price performance standards (performance based), as restricted stock to certain officers. Vesting of these shares is based on the performance of the market price of the Common Stock over the vesting period. The fair value of the performance shares was estimated on the grant date using a Monte Carlo valuation model that factors in information, including the expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance shares. Compensation expense for the performance shares is a fixed amount determined at the grant date and is recognized over the vesting period regardless of whether performance shares are awarded at the end of the vesting period. Should the shares vest, they are expected to be issued out of shares held in treasury.

In May 2014, the Company also began awarding shares of the Company's Common Stock as restricted stock (non-performance based) to its non-employee directors. The restricted stock vests quarterly during the calendar year of the award and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the shares was based on the closing price of the shares on their award date and will be recognized as compensation expense ratably over the vesting period. Upon vesting, shares are expected to be issued out of shares held in treasury.

Compensation expense for the restricted stock awards is recognized in G&A.

The following table summarizes the Company's pre-tax compensation expense for the years ended September 30, 2016, 2015 and 2014, related to the Company's performance based and non-performance based restricted stock.

	Year Ended September 30,		
	2016	2015	2014
Performance based, restricted stock	$ 390,655	$ 480,159	$ 287,789
Non-performance based, restricted stock	390,824	414,968	371,531
Total compensation expense	$ 781,479	$ 895,127	$ 659,320

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.

	Unrecognized Compensation Cost	Weighted Average Period (in years)
Performance based, restricted stock	$ 207,856	1.69
Non-performance based, restricted stock	304,409	1.52
Total	$ 512,265	

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

A summary of the status of unvested shares of restricted stock awards and changes is presented below:

	Performance Based Unvested Restricted Shares	Weighted Average Grant-Date Fair Value	Non-Performance Based Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of September 30, 2013	93,190	$ 8.82	59,768	$ 14.53
Granted	36,558	8.07	20,022	20.47
Vested	(720)	9.77	(23,437)	17.21
Forfeited	(16,844)	9.77	-	-
Unvested shares as of September 30, 2014	112,184	$ 8.42	56,353	$ 15.52
Granted	35,485	12.18	22,028	19.25
Vested	(10,209)	9.73	(38,415)	16.58
Forfeited	(25,209)	9.73	-	-
Unvested shares as of September 30, 2015	112,251	$ 9.20	39,966	$ 16.56
Granted	40,446	9.32	26,478	16.37
Vested	(10,197)	7.59	(23,433)	16.91
Forfeited	(28,083)	7.59	-	-
Unvested shares as of September 30, 2016	114,417	$ 9.79	43,011	$ 16.25

The intrinsic value of the vested shares in 2016 was $579,647.

10. INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES

Virtually all oil and natural gas producing activities of the Company are conducted within the contiguous United States (principally in Arkansas, Oklahoma and Texas) and represent substantially all of the business activities of the Company.

The following table shows sales through various operators/purchasers during 2016, 2015 and 2014.

	2016	2015	2014
Cheyenne Petroleum	23%	23%	6%
Southwestern Energy Company	12%	14%	17%
Chesapeake Operating, Inc.	4%	7%	11%

11. SUPPLEMENTARY INFORMATION ON OIL, NGL AND NATURAL GAS RESERVES (UNAUDITED)

Aggregate Capitalized Costs

The aggregate amount of capitalized costs of oil and natural gas properties and related accumulated depreciation, depletion and amortization as of September 30 is as follows:

	2016	2015
Producing properties	$ 434,469,093	$ 441,141,337
Non-producing minerals	7,364,630	8,088,134
Non-producing leasehold	204,101	204,101
Exploratory wells in progress	5,917	1,762
	442,043,741	449,435,334
Accumulated depreciation, depletion and amortization	(251,004,735)	(227,165,334)
Net capitalized costs	$ 191,039,006	$ 222,270,000

Costs Incurred

For the years ended September 30, the Company incurred the following costs in oil and natural gas producing activities:

	2016	2015	2014
Property acquisition costs	$ -	$ 146,261	$ 83,405,404
Exploration costs	21,049	898,818	2,013,231
Development costs	5,075,710	24,931,571	34,219,072
	$5,096,759	$25,976,650	$119,637,707

In 2014, $81.5 million of property acquisition costs related to the Eagle Ford Shale acquisition.

Estimated Quantities of Proved Oil, NGL and Natural Gas Reserves

The following unaudited information regarding the Company's oil, NGL and natural gas reserves is presented pursuant to the disclosure requirements promulgated by the SEC and the FASB.

Proved oil and natural gas reserves are those quantities of oil and natural gas which, by analysis of geosciences 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 that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, calculated the Company's oil, NGL and natural gas reserves as of September 30, 2016, 2015 and 2014.

The Company's net proved oil, NGL and natural gas reserves, which are located in the contiguous United States (except for an insignificant amount of international overrides), as of

September 30, 2016, 2015 and 2014, have been estimated by the Company's Independent Consulting Petroleum Engineering Firm. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principals and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

All of the reserve estimates are reviewed and approved by our Vice President and COO, who reports directly to our President and CEO. Paul Blanchard, our COO, holds a Bachelor of Science Degree in Petroleum Engineering from the University of Oklahoma. Before joining the Company, he was sole proprietor of a consulting petroleum engineering firm, spent 10 years as Vice President of the Mid-Continent business unit of Range Resources Corporation and spent several years as an engineer with Enron Oil and Gas. He is an active member of the Society of Petroleum Engineers (SPE) with over 30 years of oil and gas industry experience, including engineering assignments in several field locations.

Our COO and internal staff work closely with our Independent Consulting Petroleum Engineers to ensure the integrity, accuracy and timeliness of data furnished to them for their reserves estimation process. We provide historical information (such as ownership interest, oil and gas production, well test data, commodity prices, operating costs and handling fees, and development costs) for all properties to our Independent Consulting Petroleum Engineers. Throughout the year, our team meets regularly with representatives of our Independent Consulting Petroleum Engineers to review properties and discuss methods and assumptions.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data was available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Accordingly, these estimates should be expected to change, and such changes could be material and occur in the near term as future information becomes available.

Net quantities of proved, developed and undeveloped oil, NGL and natural gas reserves are summarized as follows:

	Proved Reserves		
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)
September 30, 2013	1,643,303	1,616,126	132,289,167
Revisions of previous estimates	(50,025)	469,897	(3,917,380)
Acquisitions (divestitures)	5,882,886	884,889	8,191,448
Extensions, discoveries and other additions	439,802	276,957	16,702,684
Production	(346,387)	(207,688)	(10,773,559)
September 30, 2014	7,569,579	3,040,181	142,492,360
Revisions of previous estimates	(1,697,309)	(425,300)	(31,273,207)
Acquisitions (divestitures)	-	-	-
Extensions, discoveries and other additions	1,619,285	516,679	18,740,114
Production	(453,125)	(210,960)	(9,745,223)
September 30, 2015	7,038,430	2,920,600	120,214,044
Revisions of previous estimates	(1,552,010)	(1,192,143)	(47,068,144)
Acquisitions (divestitures)	-	-	-
Extensions, discoveries and other additions	303,922	65,306	16,864,075
Production	(364,252)	(171,060)	(8,284,377)
September 30, 2016	5,426,090	1,622,703	81,725,598

The prices used to calculate reserves and future cash flows from reserves for oil, NGL and natural gas, respectively, were as follows: September 30, 2016 - $36.77/Bbl, $12.22/Bbl, $1.97/Mcf; September 30, 2015 - $55.27/Bbl, $19.10/Bbl, $2.84/Mcf; September 30, 2014 - $96.94/Bbl, $31.45/Bbl, $4.04/Mcf.

The revisions of previous estimates from 2015 to 2016 were primarily the result of:

- Negative pricing revisions of 64.4 Bcfe resulting from:

  a) 17.5 Bcfe of negative proved developed revisions primarily due to wells reaching their projected economic limits much earlier than projected in 2015.

  b) 46.9 Bcfe of negative PUD revisions principally attributable to the removal of PUD locations and associated reserves throughout the Company’s operating areas, primarily Fayetteville Shale and Anadarko Basin Woodford Shale, which are no longer projected to be developed within five years from the date they were added to the PUD reserves due to low commodity prices. The Company's 2016 PUD locations now stand at 106, as compared to 409 PUD locations in 2015.

- Positive performance revisions of .9 Bcfe.

Extensions, discoveries and other additions from 2015 to 2016 are principally attributable to:

- Proved developed reserve extensions, discoveries and other additions of 2.5 Bcfe principally resulting from the Company's participation in unconventional oil, NGL and natural gas in the Anadarko Woodford Shale in central and western Oklahoma and the Bakken Shale in North Dakota.

- The addition of 16.6 Bcfe of PUD reserves principally in the southeastern Oklahoma Woodford. These southeastern Oklahoma Woodford additions are the PUD reserves assigned to eight wells the Company approved to drill in late 2016. Drilling operations are underway on four wells and all eight wells are projected to begin producing in early 2017.

	Proved Developed Reserves			Proved Undeveloped Reserves		
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)
September 30, 2014	2,890,678	1,564,859	88,512,767	4,678,901	1,475,322	53,979,593
September 30, 2015	2,725,077	1,466,834	82,899,159	4,313,353	1,453,766	37,314,885
September 30, 2016	1,980,519	1,095,256	62,929,047	3,445,571	527,447	18,796,551

The following details the changes in proved undeveloped reserves for 2016 (Mcfe):

Beginning proved undeveloped reserves	71,917,599
Proved undeveloped reserves transferred to proved developed	(1,806,525)
Revisions	(44,108,114)
Extensions and discoveries	16,631,699
Purchases	-
Ending proved undeveloped reserves	42,634,659

Beginning PUD reserves were 71.9 Bcfe. A total of 1.8 Bcfe (3% of the beginning balance) were transferred to proved developed producing during 2016. The 44.1 Bcfe (61% of the beginning balance) of negative revisions to PUD reserves is attributable to a 46.9 Bcfe negative PUD revisions principally attributable to the removal of PUD locations and associated reserves throughout the Company's operating areas which are no longer projected to be developed within five years from the date they were added to the PUD reserves due to low commodity prices. These negative revisions were somewhat offset by a positive performance revisions of 2.8 Bcfe. A total of 45.9 Bcfe (64% of the beginning balance) of PUD reserves were moved out of the category during 2016 as either a result of being transferred to proved developed or removed due to low commodity prices. No PUD locations from 2012 remain in the PUD category and there are only two remaining PUD locations from 2013. The Company's total PUD locations decreased from 409 in 2015 to 106 in 2016. As a point of reference, the Company participated in 58 wells in 2016, 35 of which were conversions from PUD to PDP. We anticipate that all the Company's PUD locations will be drilled and converted to PDP within five years of the date they were added. However, PUD locations and associated reserves which are no longer projected to be drilled within five years from the date they were added to the PUD reserves will be removed as revisions at the time that determination is made. In the event that there are undrilled PUD locations at the end of the five-year period, it is our intent to remove the reserves associated with those locations from our proved reserves as revisions. The Company added 16.6 Bcfe of PUD reserves in 2016, principally in the southeastern Oklahoma Woodford. These southeastern Oklahoma Woodford Shale additions are the PUD reserves assigned to eight wells the Company approved to drill in late 2016. Drilling operations are underway on four wells, and all eight are projected to begin producing in early 2017.

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards prescribe guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying the trailing unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs to the estimated quantities of oil, NGL and natural gas to be produced. Actual future prices and costs may be materially higher or lower than the unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year.

Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carry forwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor. The assumptions used to compute the standardized measure are those prescribed by the FASB and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates affect the valuation process.

	2016	2015	2014
Future cash inflows	$ 380,263,695	$ 786,295,155	$1,405,400,261
Future production costs	(182,948,045)	(311,933,151)	(423,512,430)
Future development and asset retirement costs	(72,431,842)	(124,857,957)	(146,465,509)
Future income tax expense	(38,674,100)	(123,007,909)	(308,149,182)
Future net cash flows	86,209,708	226,496,138	527,273,140
10% annual discount	(56,439,589)	(144,904,927)	(322,490,636)
Standardized measure of discounted future net cash flows	$ 29,770,119	$ 81,591,211	$ 204,782,504

Changes in the standardized measure of discounted future net cash flows are as follows:

	2016	2015	2014
Beginning of year	$ 81,591,211	$ 204,782,504	$101,674,896
Changes resulting from:			
Sales of oil, NGL and natural gas, net of production costs	(16,749,632)	(35,359,204)	(66,239,618)
Net change in sales prices and production costs	(86,198,778)	(211,336,729)	164,240,162
Net change in future development and asset retirement costs	21,636,258	9,569,985	(46,593,511)
Extensions and discoveries	11,640,704	34,327,400	44,308,910
Revisions of quantity estimates	(41,716,689)	(51,375,950)	(3,235,695)
Acquisitions (divestitures) of reserves-in-place	-	-	102,945,609
Accretion of discount	14,424,032	37,000,855	17,646,314
Net change in income taxes	44,533,277	102,592,290	(90,457,070)
Change in timing and other, net	609,736	(8,609,940)	(19,507,493)
Net change	(51,821,092)	(123,191,293)	103,107,608
End of year	$ 29,770,119	$ 81,591,211	$204,782,504

12. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

The following is a summary of the Company's unaudited quarterly results of operations.

	Fiscal 2016 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 11,462,125	$ 7,587,091	$ 9,862,578	$ 10,151,389
Income (loss) before provision for income taxes	$ (5,167,118)	$ (12,013,161)	$ (1,730,795)	$ 913,190
Net income (loss)	$ (2,799,118)	$ (7,438,161)	$ (786,795)	$ 737,190
Earnings (loss) per share	$ (0.17)	$ (0.44)	$ (0.05)	$ 0.05

	Fiscal 2015 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 30,999,170	$ 14,679,034	$ 11,748,888	$ 13,455,001
Income (loss) before provision for income taxes	$ 14,875,761	$ 627,207	$ (496,946)	$ (848,681)
Net income (loss)	$ 10,233,761	$ 704,207	$ (728,946)	$ (887,681)
Earnings (loss) per share	$ 0.61	$ 0.04	$ (0.04)	$ (0.05)