PANHANDLE OIL & GAS INC
Form 10-Q
August 06, 2010

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the period ended June 30, 2010

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

Commission File Number 001-31759
PANHANDLE OIL AND GAS INC.
(Exact name of registrant as specified in its charter)

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

Grand Centre Suite 300, 5400 N Grand Blvd., Oklahoma City, Oklahoma 73112
(Address of principal executive offices)
Registrant s telephone number including area code (405) 948-1560

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

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

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

Large accelerated filer o Accelerated filer þ Non-accelerated filer o Smaller reporting company o
(Do not check if a smaller reporting company)

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

Outstanding shares of Class A Common stock (voting) at August 6, 2010: 8,320,136

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PART 1 FINANCIAL INFORMATION

PANHANDLE OIL AND GAS INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Information at June 30, 2010 is unaudited)

	June 30, 2010	September 30, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 2,169,634	$ 639,908
Oil and natural gas sales receivables, net of allowance for uncollectible accounts	8,205,594	7,747,557
Derivative contracts	1,548,598	
Deferred income taxes		1,934,900
Refundable production taxes	881,349	616,668
Other	1,221,884	68,817
Total current assets	14,027,059	11,007,850
Properties and equipment, at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	204,638,307	198,076,244
Non-producing oil and natural gas properties	10,184,554	10,332,537
Furniture and fixtures	600,363	578,460
	215,423,224	208,987,241
Less accumulated depreciation, depletion and amortization	129,344,929	112,900,027
Net properties and equipment	86,078,295	96,087,214
Investments	581,126	682,391
Derivative contracts	239,781	
Refundable production taxes	494,620	772,177
Total assets	$ 101,420,881	$ 108,549,632
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 4,305,954	$ 4,810,687
Derivative contracts		1,726,901
Accrued liabilities	1,706,808	1,033,570
Total current liabilities	6,012,762	7,571,158
Long-term debt		10,384,722
Deferred income taxes	22,689,650	24,064,650
Asset retirement obligations	1,639,175	1,620,225
Derivative contracts		786,534

Stockholders equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued at June 30, 2010 and at September 30, 2009	140,524	140,524
Capital in excess of par value	1,922,053	1,922,053
Deferred directors compensation	2,181,650	1,862,499
Retained earnings	71,145,347	64,507,547
	75,389,574	68,432,623
Less treasury stock, at cost; 119,866 shares at June 30, 2010 and at September 30, 2009	(4,310,280)	(4,310,280)
Total stockholders equity	71,079,294	64,122,343
Total liabilities and stockholders equity	$ 101,420,881	$ 108,549,632

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Nine Months Ended June 30, 2010	Nine Months Ended June 30, 2009
Revenues:				
Oil and natural gas sales	$ 9,659,803	$ 9,058,169	$ 32,981,230	$ 28,114,989
Lease bonuses and rentals	934,532	28,777	1,057,468	182,019
Gains (losses) on derivative contracts	(218,935)	(470,974)	5,410,714	212,578
Income of partnerships	86,470	49,244	190,694	252,889
	10,461,870	8,665,216	39,640,106	28,762,475
Costs and expenses:				
Lease operating expenses	1,681,982	2,095,933	6,166,102	5,772,401
Production taxes	236,793	369,802	1,041,738	1,117,040
Exploration costs	538,262	112,537	1,415,025	314,845
Depreciation, depletion and amortization	5,221,723	6,844,813	15,998,498	20,882,405
Provision for impairment		115,892	12,370	2,124,133
Loss (gain) on asset sales, interest and other	(989,152)	(46,564)	(987,333)	(143,022)
General and administrative	1,507,962	1,174,315	4,353,462	3,721,070
	8,197,570	10,666,728	27,999,862	33,788,872
Income (loss) before provision (benefit) for income taxes	2,264,300	(2,001,512)	11,640,244	(5,026,397)
Provision (benefit) for income taxes	753,000	(1,073,000)	3,257,000	(2,278,000)
Net income (loss)	$ 1,511,300	$ (928,512)	$ 8,383,244	$ (2,748,397)
Basic and diluted earnings (loss) per common share (Note 3)	$ 0.18	$ (0.11)	$ 1.00	$ (0.33)
Basic and diluted weighted average shares outstanding:				
Common shares	8,311,636	8,300,128	8,311,636	8,300,128
Unissued, vested directors shares	112,160	97,867	110,640	96,325
	8,423,796	8,397,995	8,422,276	8,396,453
Dividends declared per share of common stock and paid in period	$ 0.07	$ 0.07	$ 0.21	$ 0.21

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(Information at and for the nine months ended June 30, 2010 and June 30, 2009 is unaudited)
Nine Months Ended June 30, 2010

	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, 2009	8,431,502	$ 140,524	$ 1,922,053	$ 1,862,499	$ 64,507,547	(119,866)	$ (4,310,280)	$ 64,122,343
Net income					8,383,244			8,383,244
Dividends ($.21 per share)					(1,745,444)			(1,745,444)
Increase in deferred directors compensation charged to expense				319,151				319,151
Balances at June 30, 2010	8,431,502	$ 140,524	$ 1,922,053	$ 2,181,650	$ 71,145,347	(119,866)	$ (4,310,280)	$ 71,079,294

Nine Months Ended June 30, 2009

	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, 2008	8,431,502	$ 140,524	$ 2,090,070	$ 1,605,811	$ 69,236,604	(131,374)	$ (4,724,108)	$ 68,348,901
Net loss					(2,748,397)			(2,748,397)
Dividends ($.21 per share)					(1,743,027)			(1,743,027)
Increase in deferred directors				230,237				230,237

compensation charged to expense								
Balances at June 30, 2009	8,431,502	$ 140,524	$ 2,090,070	$ 1,836,048	$ 64,745,180	(131,374)	$ (4,724,108)	$ 64,087,714

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine months ended June 30, 2010	2009
Operating Activities		
Net income (loss)	$ 8,383,244	$ (2,748,397)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Unrealized (gains) losses on natural gas derivative contracts	(4,301,814)	1,569,822
Depreciation, depletion, amortization and impairment	16,010,868	23,006,628
Provision for deferred income taxes	613,000	(3,125,000)
Exploration costs	1,039,905	314,845
Net (gain) loss on sale of assets and other	(1,139,072)	(181,760)
Income from partnerships	(190,694)	(252,889)
Distributions received from partnerships	270,817	308,182
Directors deferred compensation expense	319,151	230,237
Other	64,555	
Cash provided by changes in assets and liabilities:		
Oil and natural gas sales receivables	(458,037)	9,634,657
Refundable income taxes		2,162,305
Refundable production taxes	12,876	(474,810)
Other current assets	(1,153,067)	(138,232)
Accounts payable	143,270	106,136
Income taxes payable	360,966	165,919
Accrued liabilities	259,172	39,902
Total adjustments	11,851,896	33,365,942
Net cash provided by operating activities	20,235,140	30,617,545
Investing Activities		
Capital expenditures, including dry hole costs	(8,189,105)	(35,509,890)
Proceeds from leasing of fee mineral acreage	1,256,102	202,007
Investments in partnerships	(43,413)	
Proceeds from sales of assets	401,168	2,514,343
Net cash used in investing activities	(6,575,248)	(32,793,540)
Financing Activities		
Borrowings under debt agreement	10,799,814	43,705,195
Payments of loan principal	(21,184,536)	(40,076,791)
Payments of dividends	(1,745,444)	(1,743,027)
Net cash provided by (used in) financing activities	(12,130,166)	1,885,377
Increase (decrease) in cash and cash equivalents	1,529,726	(290,618)

Cash and cash equivalents at beginning of period	639,908	895,708
Cash and cash equivalents at end of period	$ 2,169,634	$ 605,090
Supplemental Schedule of Noncash Investing and Financing Activities		
Additions to asset retirement obligations	$ 18,950	$ 168,567
Gross additions to properties and equipment	$ 7,541,102	$ 24,069,809
Net (increase) decrease in accounts payable for properties and equipment additions	648,003	11,440,081
Capital expenditures, including dry hole costs	$ 8,189,105	$ 35,509,890

(See accompanying notes)

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PANHANDLE OIL AND GAS INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1: Accounting Principles and Basis of Presentation

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

Certain amounts and disclosures have been condensed or omitted from these consolidated financial statements pursuant to the rules and regulations of the SEC. Therefore, these condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes thereto included in the Company s 2009 Annual Report on Form 10-K.

NOTE 2: Income Taxes

The Company s provision or benefit for income taxes (both federal and state) differs from the statutory rate primarily due to estimated federal and state benefits generated from estimated excess federal and Oklahoma percentage depletion (permanent tax benefits).

Excess federal percentage depletion (limited to certain production volumes and by certain net income levels) and excess Oklahoma percentage depletion (with no limitation on production volume or net income) reduces estimated taxable income or adds to estimated taxable loss projected for any year. The federal and Oklahoma excess percentage depletion allowance estimates will be updated throughout the year until finalized with the detail well-by-well calculations at fiscal year-end. Federal and Oklahoma excess percentage depletion benefits, when a provision for income taxes is recorded, decrease the effective tax rate (as is the case as of June 30, 2010), while the effect is to increase the effective tax rate when a benefit for income taxes is recorded. The benefits of federal and Oklahoma excess percentage depletion are not directly related to the amount of pre-tax loss or income recorded in a period. Accordingly, in periods where a recorded pre-tax income or loss is relatively small, the proportional effect of these items on the effective tax rate may be significant.

A valuation allowance was recorded in fiscal 2009 of $278,000 on certain Oklahoma state tax net operating loss carryforwards (NOL). Due to lower expected levels of intangible drilling costs to be incurred during fiscal 2010, the Company expects to be able to utilize approximately $212,000 of these Oklahoma NOL benefits in fiscal 2010. Therefore, the Company has removed $212,000 of the Oklahoma NOL valuation allowance in fiscal 2010, leaving a net valuation allowance of $66,000 representing Oklahoma NOL benefits the Company no longer believes are more likely than not to be utilized in future periods prior to expiration.

NOTE 3: Earnings (Loss) per Share

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

In June 2010, the Company awarded 8,500 shares of restricted stock to certain officers. The restricted stock vests at the end of five years and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the awards is approximately $240,000 and will be recognized as compensation expense over the vesting period. In accordance with accounting guidance, the outstanding stock awards for the quarter ended June 30, 2010 are not included in the diluted earnings per share calculation.

NOTE 4: Long-term Debt

The Company has a credit facility with Bank of Oklahoma (BOK) which consists of a revolving loan in the amount of $50,000,000 which is subject to a semi-annual borrowing base determination, wherein BOK applies their own current pricing forecast and a 9% discount rate to the Company s proved reserves as calculated by the Company s consulting petroleum engineering firm. When applying the discount rate, BOK also applies an advance rate percentage to risk all proved non-producing and proved undeveloped reserves. Effective February 3, 2009, the Company amended its revolving credit facility with BOK to increase the borrowing base from $15,000,000 to $25,000,000 (the revolving loan amount remains $50,000,000), restructure the interest rate, secure the loan by certain of the Company s properties (with a carrying value of $31,850,867 at June 30, 2010) and change the maturity date to October 31, 2011. Effective May 20, 2009 the Company again increased the borrowing base from $25,000,000 to $35,000,000. On December 8, 2009 and May 25, 2010, Panhandle s bank reaffirmed the Company s $35,000,000 borrowing base and extended the maturity date of the credit facility to October 31, 2012. The restructured interest rate is based on national prime plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%, with an established interest rate floor of 4.50% annually. The 4.50% interest rate floor was in effect at June 30, 2010, but has subsequently been removed. 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. The interest rate spread from national prime or LIBOR will be charged based on the percent of the value advanced of the calculated loan value of the Company s oil and natural gas properties.

Determinations of the borrowing base are made semi-annually or whenever the bank, in its sole discretion, believes that there has been a material change in the value of the oil and natural gas properties. 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 June 30, 2010, the Company was in compliance with the covenants of the BOK agreement.

NOTE 5: Dividends

On May 19, 2010, the Company s Board of Directors approved payment of a $.07 per share dividend that was paid on June 14, 2010 to shareholders of record on June 1, 2010.

NOTE 6: Deferred Compensation Plan for Directors

The Company has a deferred compensation plan for non-employee directors (Plan). The Plan provides that each eligible director can individually elect to receive shares of Company stock rather than cash for board and committee chair retainers, board meeting fees and board committee meeting fees. These shares are unissued and vest as earned. The shares are credited to each director s deferred fee account at the closing market price of the stock on the date earned. 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.

NOTE 7: Oil and Natural Gas Reserves

The estimation of crude oil and natural gas reserves affects depreciation, depletion and amortization (DD&A) and impairment calculations. On an annual basis, with a semi-annual update, the Company s consulting engineer, with assistance from Company staff, prepares estimates of crude oil 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. Separate reserve estimates are made using current and projected future prices of crude oil and natural gas. According to guidelines and definitions established by the SEC, DD&A must be calculated using non-escalated prices current with the period end for which estimates are being made, while reserve estimations used in assessments for asset impairments are calculated using projected future crude oil and natural gas prices. When significant crude oil and natural gas price changes occur between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing price decks current with the period. For DD&A calculation purposes, crude oil and natural gas reserves as of June 30, 2010 were updated, utilizing June 30, 2010 crude oil and natural gas prices ($70.89 per barrel of crude oil and $3.84 per Mcf of natural gas) held flat over the lives of the properties. The update of crude oil and natural gas reserves utilizing price decks as of June 30, 2010 positively impacted the reserves (compared to reserves at September 30, 2009) as the higher prices extended the economic lives of several of the Company s properties resulting in higher overall reserve volumes. The higher prices resulted in upward revisions (compared to reserves at September 30, 2009) to proved crude oil and natural gas reserves of approximately 27,000 barrels and 5.7 Bcf, respectively. In comparison, prices used for the September 30, 2009 annual report were $66.96 per barrel of crude oil and $2.86 per Mcf of natural gas held flat over the lives of the properties. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

The Company will not adopt the SEC Modernization of Oil and Gas reporting requirements until September 30, 2010, as early adoption is not permitted.

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NOTE 8: Impairment

All long-lived assets, principally oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its estimated future net cash flows. The evaluations involve significant judgment since the results are based on estimated future events, such as inflation rates, future sales prices for oil and natural gas, future production costs, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil and natural gas reserves. When significant crude oil and natural gas price changes occur between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing updated projected future price decks current with the period. The assessment at June 30, 2010 resulted in no charge to impairment. As of the quarter ended June 30, 2009, the Company s test for impairment resulted in a charge to impairment of $115,892. A reduction in oil and natural gas prices or a decline in reserve volumes could lead to additional impairment that may be material to the Company.

NOTE 9: Capitalized Costs

Oil and natural gas properties include costs of $541,151 on exploratory wells which were drilling and/or testing at June 30, 2010. The Company is expecting to have evaluation results on these wells within the next six months.

NOTE 10: Derivatives

In the past, the Company entered into costless collar contracts (all of which expired in the 2009 first quarter). Currently, the Company has entered into fixed swap contracts and basis protection swaps. These instruments are intended to reduce the Company s exposure to short-term fluctuations in the price of natural gas. Fixed swap contracts set a fixed price and provide payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price. These contracts cover only a portion of the Company s natural gas production and provide only partial price protection against declines in natural gas prices. Basis protection swaps are derivatives that guarantee a price differential to Nymex for natural gas from a specified delivery point (CEGT and PEPL currently). The Company receives a payment from the counterparty if the price differential is greater than the agreed terms of the contract and pays the counterparty if the price differential is less than the agreed terms of the contract. These derivative instruments may expose the Company to risk of financial loss and limit the benefit of future increases in prices. All of the Company s derivative contracts are with Bank of Oklahoma and are unsecured. The derivative instruments have settled or will settle based on the prices below which are adjusted for location differentials and tied to certain pipelines in Oklahoma.

Derivative contracts in place as of September 30, 2009
(prices below reflect the Company s net price from the listed Oklahoma pipelines)

Contract period	Production volume covered per month	Indexed (1) Pipeline	Fixed price
March December, 2009	60,000 Mmbtu	CEGT	$4.010
April December, 2009	100,000 Mmbtu	CEGT	$3.710
May December, 2009	70,000 Mmbtu	CEGT	$3.615
July December, 2009	70,000 Mmbtu	PEPL	$3.745
January December, 2010	100,000 Mmbtu	CEGT	$5.015
January December, 2010	50,000 Mmbtu	CEGT	$5.050

January December, 2010	100,000 Mmbtu	PEPL	$5.570
January December, 2010	50,000 Mmbtu	PEPL	$5.560

(1) CEGT Centerpoint Energy Gas Transmission s East pipeline in Oklahoma

PEPL Panhandle Eastern Pipeline Company s Texas/Oklahoma mainline

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Derivative contracts in place as of June 30, 2010
(prices below reflect the Company s net price from the listed Oklahoma pipelines)

Contract period	Production volume covered per month	Indexed (1) Pipeline	Fixed price
Fixed price swaps			
January December, 2010	100,000 Mmbtu	CEGT	$5.015
January December, 2010	50,000 Mmbtu	CEGT	$5.050
January December, 2010	100,000 Mmbtu	PEPL	$5.570
January December, 2010	50,000 Mmbtu	PEPL	$5.560
Basis protection swaps			
January December, 2011	50,000 Mmbtu	CEGT	Nymex -$.27
January December, 2011	50,000 Mmbtu	CEGT	Nymex -$.27
January December, 2011	50,000 Mmbtu	PEPL	Nymex -$.26
January December, 2011	50,000 Mmbtu	PEPL	Nymex -$.27
January December, 2012	50,000 Mmbtu	CEGT	Nymex -$.29
January December, 2012	40,000 Mmbtu	CEGT	Nymex -$.30
January December, 2012	50,000 Mmbtu	PEPL	Nymex -$.29
January December, 2012	50,000 Mmbtu	PEPL	Nymex -$.30

(1) CEGT Centerpoint Energy Gas Transmission s East pipeline in Oklahoma

PEPL Panhandle Eastern Pipeline Company s Texas/Oklahoma mainline

While the Company believes that its derivative contracts are effective in achieving the risk management objective for which they were intended, the Company has elected not to complete all of the documentation requirements necessary to permit these derivative contracts to be accounted for as cash flow hedges. The Company s fair value of derivative contracts was a net asset of $1,788,379 as of June 30, 2010 and a liability of $2,513,435 as of September 30, 2009. Realized and unrealized gains and (losses) for the periods ended June 30, 2010 and 2009 are scheduled below:

Gains (losses) on natural gas derivative contracts - current	Three months ended 6/30/2010	Three months ended 6/30/2009	Nine months ended 6/30/2010	Nine months ended 6/30/2009
Realized	$ 1,297,500	$ 660,400	$ 1,108,900	$ 1,782,400
Increase (decrease) in fair value	(1,767,782)	(519,674)	3,275,499	(675,582)
Total	$ (470,282)	$ 140,726	$ 4,384,399	$ 1,106,818

Gains (losses) on natural gas derivative contracts - long-term	Three months ended 6/30/2010	Three months ended 6/30/2009	Nine months ended 6/30/2010	Nine months ended 6/30/2009
Realized	$	$	$	$
Increase (decrease) in fair value	251,347	(611,700)	1,026,315	(894,240)
Total	$ 251,347	$ (611,700)	$ 1,026,315	$ (894,240)

To the extent that a legal offset exists, the Company nets the fair value of its derivative contracts with the same counterparty in the accompanying balance sheets. The following table summarizes the Company s derivative contracts as of June 30, 2010 and September 30, 2009:

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	Balance Sheet Location	6/30/2010 Fair Value	9/30/2009 Fair Value
Asset Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$ 1,548,598	$
Commodity contracts	Long-term derivative contracts	239,781	
Total Asset Derivatives (a)		$ 1,788,379	$
Liability Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$	$ 1,726,901
Commodity contracts	Long-term derivative contracts		786,534
Total Liability Derivatives (a)		$	$ 2,513,435

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

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

NOTE 11: Exploration Costs

In the quarter and nine month period ended June 30, 2010, lease expirations and leasehold impairments of $163,131 and $1,040,055, respectively, were charged to exploration costs. Leasehold impairments are recorded for individually insignificant non-producing leases which the Company believes will not be transferred to proved properties over the remaining lives of the leases. In the quarter ended June 30, 2010, the Company also had additional costs of $375,131 related to exploratory Geographical and Geophysical expenses and dry hole adjustments. In the quarter, the Company purchased 3-D seismic rights for $375,120 in an unproved area in eastern Oklahoma. In the quarter and nine month period ended June 30, 2009, lease expirations and impairments of $89,839 and $256,053, respectively, were charged to exploration costs as well as additional costs of $22,698 and $58,792, respectively, related to exploratory dry holes.

NOTE 12: Fair Value Measurements

Effective October 1, 2008, the Company adopted guidance which established a framework for measuring the fair value of assets and liabilities measured on a recurring basis and expanded disclosures about fair value measurements.

In February 2008, the FASB delayed the effective date of this guidance by one year for nonfinancial assets and liabilities. Consequently, the Company only applied the fair value measurement statement to financial assets and liabilities and delayed application for nonfinancial assets and liabilities (including, but not limited to, its asset retirement obligations) until the Company s fiscal year beginning October 1, 2009, as permitted. Upon adoption as of October 1, 2009, the impact of full application for nonfinancial assets and liabilities on its financial position, results of operations and cash flows was not material.

This guidance defines fair value 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. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2010.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative Contracts Swaps	$	$1,788,379	$	$1,788,379

Level 2 The fair values of the Company s natural gas 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, among other things, future prices and time to maturity. These values are then compared to the values given by our counterparties for reasonableness. Since the natural gas swaps do not have unobservable inputs, they are classified as Level 2.

NOTE 13: Fair Values of Financial Instruments

The carrying amounts reported in the balance sheets for cash and cash equivalents, receivables, refundable income taxes, accounts payable and accrued liabilities approximate their fair values due to the short maturity of these instruments. The fair value of the Company s debt at September 30, 2009 approximates its carrying amount due to the interest rates on the Company s revolving line of credit being rates which are approximately equivalent to market rates for similar type debt based on the Company s credit worthiness.

NOTE 14: Lawsuit Settlement

The Company benefited $1,124,682 from the settlement of a lawsuit related to one well in western Oklahoma, payment of which was received in July 2010. This amount is included in Loss (gain) on asset sales, interest and other on the face of the Condensed Consolidated Statements of Operations.

NOTE 15: New Accounting Pronouncements

In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which, as of July 1, 2009, became the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The ASC was not intended to change U.S. GAAP. Rather, the ASC reorganizes all previous U.S. GAAP pronouncements into accounting topics, and displays all topics using a consistent structure. All existing standards that were used to create the ASC are now superseded, aside from those issued by the SEC, replacing the previous references to specific Statements of Financial Accounting Standards with numbers used in the ASC s structural organization. The ASC is effective for financial statements that cover interim and annual periods ending after September 15, 2009. There was no impact on the Company s financial position, results of operations or cash flows as a result of the Accounting Standards Codification.

In December 2008, the SEC issued revised reporting requirements for oil and natural gas reserves that a company holds. Included in the new rule entitled *Modernization of Oil and Gas Reporting Requirements,* are the following changes: 1) permits use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; 2) enables companies to additionally disclose their probable and possible reserves to investors, in addition to their proved reserves; 3) allows previously excluded resources, such as oil sands, to be classified as oil and natural gas reserves rather than mining reserves; 4) requires companies to report the independence and qualifications of a preparer or auditor, based on current Society of Petroleum Engineers criteria; 5) requires the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and 6) requires companies to report oil and natural gas reserves using an average sales price based upon the prior 12-month period, rather than period-end prices. The new requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. The Company is currently assessing the impact that adoption of this rule will have on its financial disclosures.

In January 2010, the FASB issued an Accounting Standards Update (ASU) entitled *Oil and Gas Reserve Estimation and Disclosures.* This ASU amends the FASB accounting standards to align the reserve calculation and disclosure requirements with the requirements in the new SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. The ASU will be effective for annual reporting periods ending on or after December 31, 2009.

On January 21, 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update, Improving Disclosures about Fair Value Measurements . The ASU amends ASC 8201 to require additional disclosures regarding fair value measurements. The ASU is effective for interim and annual reporting periods beginning after December

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15, 2009. The adoption of the ASU did not have a material impact on the Company s financial position, results of operations, cash flow statements, or disclosures.

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

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

FORWARD-LOOKING STATEMENTS AND RISK FACTORS

Forward-Looking Statements for fiscal 2010 and later periods are made in this document. Such statements represent estimates by management based on the Company s historical operating trends, its proved oil and natural gas reserves and other information currently available to management. The Company cautions that the Forward-Looking Statements provided herein are subject to all the risks and uncertainties incident to the acquisition, development and marketing of, and exploration for oil and natural gas reserves. Investors should also read the other information in this Form 10-Q and the Company s 2009 Annual Report on Form 10-K where risk factors are presented and further discussed. For all the above reasons, actual results may vary materially from the Forward-Looking Statements and there is no assurance that the assumptions used are necessarily the most likely to occur.

LIQUIDITY AND CAPITAL RESOURCES

The Company had positive working capital of $8,014,297 at June 30, 2010 compared to positive working capital of $3,436,692 at September 30, 2009 as detailed below:

ANALYSIS OF CHANGE IN WORKING CAPITAL

	As of 6/30/2010	As of 9/30/2009	Change
CURRENT ASSETS:			
Cash and cash equivalents **(1)**	$ 2,169,634	$ 639,908	$ 1,529,726
Oil and natural gas sales receivables (net)	8,205,594	7,747,557	458,037
Derivative contracts **(2)**	1,548,598		1,548,598
Deferred income taxes **(3)**		1,934,900	(1,934,900)
Refundable production taxes **(4)**	881,349	616,668	264,681
Other **(5)**	1,221,884	68,817	1,153,067
Total current assets	14,027,059	11,007,850	3,019,209
CURRENT LIABILITIES:			
Accounts payable	4,305,954	4,810,687	(504,733)
Derivative contracts **(2)**		1,726,901	(1,726,901)
Accrued liabilities **(6)**	1,706,808	1,033,570	673,238
Total current liabilities	6,012,762	7,571,158	(1,558,396)
WORKING CAPITAL	$ 8,014,297	$ 3,436,692	$ 4,577,605

(1) During fiscal 2010, cash provided by operating activities has exceeded cash used in investing activities enabling the Company to completely pay off its line-of-credit during May 2010. Cash flow previously applied to debt retirement has been retained.

(2) The Company s current portion of fair value of derivative contracts has changed from a liability of $1,726,901 as of September 30, 2009 to an asset of $1,548,598 as of June 30, 2010 due to lower forward looking natural gas prices as of June 30, 2010. The Company has received net payments relative to its derivative contracts of $1,108,900 during fiscal 2010.

(3) Approximately $1,039,000 of the decrease in the current assets portion of deferred income taxes relates to

expected
utilization of the
Company s
Alternative
Minimum Tax
(AMT) credit
during fiscal
2010. The
change

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from a liability to an asset in the unrealized value of the Company s derivative contracts (as mentioned above) decreased the current asset portion of deferred income taxes approximately $896,000.

(4) Refundable production taxes of approximately $759,000 previously reported as non-current have now become current, thus increasing current refundable production taxes. This increase was partially offset by payments received during the first nine months of fiscal 2010 of approximately $459,000.

(5) Other current assets at June 30, 2010 include a receivable of $1,124,682 for the settlement of a lawsuit relative to one well in western Oklahoma.

(6) Income taxes payable increased $414,066 on higher net income before tax. Accrued liabilities for employee bonuses and ESOP contribution increased a combined $281,717.

Cash flow provided by operating activities was $20,235,140 as of June 30, 2010 compared to $30,617,545 as of June 30, 2009, a 34% decrease. The following schedule and footnotes explain major elements of the decrease:

ANALYSIS OF CHANGE IN CASH PROVIDED BY OPERATING ACTIVITIES

	9 months ended 6/30/2010	9 months ended 6/30/2009	Change
Net income (loss)	$ 8,383,244	$ (2,748,397)	$ 11,131,641
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Unrealized gains (losses) on natural gas derivative contracts **(1)**	(4,301,814)	1,569,822	(5,871,636)
Depreciation, depletion, amortization and impairment **(2)**	16,010,868	23,006,628	(6,995,760)
Deferred income taxes **(3)**	613,000	(3,125,000)	3,738,000
Exploration costs **(4)**	1,039,905	314,845	725,060
Net (gain) loss on sale of assets	(1,139,072)	(181,760)	(957,312)
Income from partnerships	(190,694)	(252,889)	62,195
Distributions received from partnerships	270,817	308,182	(37,365)
Directors deferred compensation	319,151	230,237	88,914
Other	64,555		64,555
Cash provided by changes in assets and liabilities:			
Oil and natural gas sales receivables **(5)**	(458,037)	9,634,657	(10,092,694)
Refundable income taxes **(6)**		2,162,305	(2,162,305)
Refundable production taxes	12,876	(474,810)	487,686
Other current assets	(1,153,067)	(138,232)	(1,014,835)
Accounts payable	143,270	106,136	37,134
Income taxes payable **(6)**	360,966	165,919	195,047
Accrued liabilities	259,172	39,902	219,270
Net cash provided by operating activities	$ 20,235,140	$ 30,617,545	$ (10,382,405)

(1) During the first nine months of fiscal 2010, the Company had an unrealized gain related to derivative contracts of $4,301,814. During the first nine months of fiscal 2009, the Company had an unrealized loss related to derivative contracts of $1,569,822.

(2) Depreciation, depletion and amortization (DD&A) declined as a result of a decline in oil and natural gas production, increased oil and natural gas reserves and a net reduction during fiscal year 2009 in asset basis. as DD&A, impairment and basis in assets sold exceeded additions to properties and equipment. An impairment of $12,370 was recorded in the 2010 period compared to $2,124,133 in the 2009 period.

For further discussion related to these items, see Depreciation, Depletion and Amortization and Provision for Impairment in Management s Discussion and Analysis.

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(3) The deferred income tax expense change of $3,738,000 resulted from a provision for deferred income taxes during the first nine months of fiscal 2010 of $613,000 compared to a deferred income tax benefit of $3,125,000 during the first nine months of fiscal 2009. Deferred income tax provisions or benefits are primarily related to expenditures for intangible drilling costs which are expensed for tax purposes in the year incurred, but amortized over the life of the oil and natural gas properties for financial purposes; thus creating an income tax timing difference. Levels of expenditures for intangible drilling costs in relation to the before tax income or loss were significantly higher in the fiscal year 2009 period than in the fiscal 2010 period.

(4) Leases expired or impaired during the fiscal 2010 period exceeded those expired or impaired during the fiscal 2009 period by approximately $784,000.

(5) Through June 30, 2010, oil and natural gas sales receivables increased primarily due to higher average oil and natural gas prices; whereas, through June 30, 2009 oil and natural gas sales receivables had decreased primarily as a result of lower average oil and natural gas prices. The net change to cash provided by operating activities was a decrease of $10,092,694 as receivables collected during the fiscal 2009 period exceeded those collected during the fiscal 2010 period.

(6) During the first nine months of fiscal 2010, income taxes payable increased \$360,966; whereas, during the first nine months of fiscal 2009 income taxes payable increased \$165,919 resulting in a positive impact to net cash provided by operating activities of \$195,047. Refundable income taxes did not change during the nine months ended June 30, 2010 and decreased \$2,162,305 (primarily due to refund payments of approximately \$2.2 million) during the nine months ended June 30, 2009. Refundable income taxes and income taxes payable overall net effect on changes in net cash provided by operating activities is a

negative effect
of $1,967,258.

Additions to properties and equipment for oil and natural gas activities as of June 30, 2010 were $7,541,102 ($24,069,809 as of June 30, 2009). Although average natural gas prices during the first nine months of fiscal 2010 have been higher than the first nine months of fiscal 2009, the Company has not experienced an increase in drilling opportunities during fiscal 2010 to the extent management expected. However, during the third quarter of fiscal 2010 there has been an increase in the number of well proposals received by the Company, and management expects the Company to participate as a working interest owner in the drilling of most of these wells. These participations are expected to moderately increase additions to properties and equipment during the fourth quarter of fiscal 2010. Management currently projects fiscal 2010 properties and equipment additions to be approximately $12.5 million compared to approximately $28.5 million during fiscal 2009.

As a part of this activity increase, we are participating as a working interest owner in two relatively new horizontal drilling plays, the Anadarko (Cana) Woodford Shale and the Horizontal Granite Wash, both in western Oklahoma. These plays, combined with continued drilling in the Southeast Oklahoma Woodford Shale and the Arkansas Fayetteville Shale areas should provide us with a reasonable number of drilling opportunities. Recently, several operators have begun to focus their drilling in areas that offer liquids-rich natural gas or oil production. The Company has significant acreage positions in some of these areas, which also is expected to further enhance drilling opportunities to the Company.

However, due to the Company not being the operator of any of its oil and natural gas properties, it is extremely difficult for us to predict levels of participation in drilling and completing new wells, and associated capital expenditures, with certainty.

For the nine months ended June 30, 2010, cash provided by operating activities was $20,235,140; well in excess of capital expenditures of $8,189,105. This allowed us to reduce bank debt by $10,384,722, which completely paid off the Company s line-of-credit as of June 30, 2010. Looking forward, the Company expects to fund capital additions, overhead costs and dividend payments primarily from cash provided by operating activities. However, during times of oil and natural gas price decreases, or increased expenditures for drilling, the Company utilized its revolving line-of-credit facility to help fund these expenditures. The Company s continued drilling activity, combined with normal delays in receiving first payments from new production, could also result in future borrowings under the Company s credit facility. The Company has availability ($35 million at June 30, 2010) under its revolving credit facility and also is well within compliance on its debt covenants (current ratio, debt to EBITDA, tangible net worth and dividends as a percent of operating cash flow). While the Company believes the availability could be increased (if needed) by placing more of the Company s properties as security under the revolving credit facility, increases are at the discretion of the bank.

RESULTS OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2010 COMPARED TO THREE MONTHS ENDED JUNE 30, 2009

Overview:

The Company recorded a third quarter 2010 net income of $1,511,300, or $.18 per share, compared to a net loss of $928,512, or $.11 per share, in the 2009 quarter. The net income was due to increased oil and natural gas revenues, increased lease bonuses, decreased DD&A and the recording of a benefit from the settlement of a lawsuit (recorded as a part of loss (gain) on asset sales, interest and other), partially offset by increased provision for income taxes. These items are further discussed below.

Revenues:

Total revenues were up $1,796,654 or 21% for the 2010 quarter compared to the 2009 quarter. The revenue growth was primarily the result of increased lease bonuses and rentals of $905,755 and increased oil and natural gas revenue of $601,634. The increase in lease bonuses is the result of the renewal of leases on a majority of the Company s non-producing mineral acreage in Arkansas which had June 2010 expiration dates. Oil and gas revenue increases are the result of increased average oil and natural gas prices of 37% and 25%, respectively, partially offset by decreases in oil and natural gas sales volumes of 21% and 15%, respectively. The table below outlines the Company s sales volumes and average sales prices for oil and natural gas for the three month periods of fiscal 2010 and 2009:

	Barrels Sold	Average Price	Mcf Sold	Average Price	Mcfe Sold	Average Price
Three months ended 6/30/10	26,873	$73.65	2,074,998	$3.70	2,236,236	$4.32
Three months ended 6/30/09	34,145	$53.89	2,442,604	$2.96	2,647,474	$3.42

Decreased drilling activity which began in 2009 has continued through the first nine months of fiscal 2010 resulting in an expected production decrease compared to the first nine months of fiscal 2009.

Depressed natural gas prices experienced in fiscal 2009, and to some degree thus far in fiscal 2010, have resulted in fewer net well proposals to the Company. Also, the Company has been very selective, only participating as a working interest owner in proposed wells with acceptable projected rates of return. Although drilling opportunities have decreased through much of the last year, the Company does own working interests in newly completed wells which began producing during the third quarter of fiscal 2010. Production from some of these new wells is significant and is expected to contribute to the Company s natural gas production and help mitigate the current decline in production. Management expects average natural gas prices for 2010 to exceed those of 2009 and anticipates the Company s drilling activity to increase during the remainder of fiscal 2010. Drilling activity which has begun in two major plays in western Oklahoma where the Company owns mineral acreage, the Anadarko (Cana) Woodford Shale and the horizontal Granite Wash, is increasing, which also should provide additional drilling opportunities for the Company.

Sales volumes by quarter for the last five quarters were as follows:

Quarter ended	Barrels Sold	Mcf Sold	Mcfe Sold
6/30/10	26,873	2,074,998	2,236,236
3/31/10	21,998	1,958,166	2,090,154
12/31/09	27,454	2,113,409	2,278,133
9/30/09	29,011	2,181,985	2,356,051
6/30/09	34,145	2,442,604	2,647,474

Gains (Losses) on Natural Gas Derivative Contracts:

The Company had a net loss of $218,935 in the three months ended June 30, 2010 compared to a loss of $470,974 for the three months ended June 30, 2009. The Company received net cash payments (realized gains) under the contracts of $1,297,500 and $660,400 for the three months ended June 30, 2010 and 2009, respectively.

Lease Operating Expenses (LOE):

LOE decreased $413,951 or 20% in the 2010 quarter. LOE per Mcfe decreased from $.79 in the 2009 quarter to $.75 in the 2010 quarter. The decrease in both total LOE and LOE per Mcfe are the result of fewer new well additions and fewer workovers and repairs in the 2010 quarter compared to the 2009 quarter. Newly completed wells incur high initial LOE costs during the first several months of operation. During the 2009 quarter several new wells began production and also a significant number of well workover and repair costs were incurred.

Production Taxes:

Production taxes decreased $133,009 or 36% in the 2010 quarter. Approximately $93,000 of the decrease relates to production tax refunds received on the Thomas 1-7, a deep vertical well in Washita County Oklahoma. We do not accrue for deep well production tax exemptions as the state of Oklahoma caps the refunds and proportionally allocates that amount to all qualified deep wells in the state. This makes a refund impractical to estimate. The increase in the proportion of the Company s oil and natural gas revenues that come from horizontal shale plays in Arkansas and Oklahoma which qualify for production tax reductions or refunds accounts for the remaining production tax decrease of approximately $40,000.

Exploration Costs:

Exploration costs were up $425,725 in the 2010 quarter compared to the 2009 quarter. The Company charged approximately $375,000 to exploration costs in the 2010 quarter related to geological and geophysical costs paid upon the execution of a joint exploration agreement with a privately held independent operator to explore for oil in eastern Oklahoma. During the 2010 quarter, leasehold impairment and expired leases totaled $163,131 compared to $89,839 during the 2009 quarter, a $73,292 increase. Two exploratory dry holes incurred expenses of approximately $22,000 during the 2009 quarter; no exploratory dry holes were drilled during the 2010 quarter.

Depreciation, Depletion and Amortization (DD&A):

DD&A decreased $1,623,090 or 24% in the 2010 quarter. DD&A per Mcfe in the 2010 quarter was $2.34 as compared to $2.59 in the 2009 quarter. Oil and natural gas production decreased 16% in the 2010 quarter accounting for approximately $1,063,000 of the DD&A decrease. The remaining DD&A decrease of approximately $560,000 is attributable to the $.25 decline in the DD&A rate per Mcfe. This rate declined as a result of increased oil and natural gas reserves as of June 30, 2010 compared to June 30, 2009, and a net reduction during fiscal year 2009 of approximately $3.1 million of asset basis subject to DD&A. This asset basis reduction occurred as fiscal 2009 DD&A and impairment, combined with the basis reduction associated with assets sold, exceeded new additions to properties and equipment for oil and natural gas activities.

Provision for Impairment:

The provision for impairment decreased $115,892 in the 2010 quarter. No impairment was recorded during the 2010 quarter. One field was impaired during the 2009 quarter a total of $115,892.

Loss (Gain) on Asset Sales, Interest and Other:

The Company benefited $1,124,682 from the settlement of a lawsuit related to one well in western Oklahoma, payment of which was received in July 2010. The Company sold its working interest in the Keahey 1-19H well at a loss of $315,647 during the third quarter of fiscal 2010. Also included is a gain of $217,868 for the sale of leasehold in Roger Mills County, Oklahoma.

General and Administrative Costs (G&A):

In the 2010 quarter, G&A costs increased $333,647 or 28%. The increase is primarily related to increases in the following expense categories: legal $156,078, personnel $111,700, audit and tax preparation fees $36,760 and insurance $34,526. Legal expense increased primarily due to legal costs incurred during the 2010 quarter on a lawsuit involving one well in western Oklahoma, whereas no like expenses were incurred during the 2009 quarter. The increase in personnel expenses mainly relate to higher accrued performance bonuses based on expected improved Company performance metrics in the fiscal 2010 quarter compared to the 2009 quarter.

Income Taxes:

The 2010 quarter provision for income taxes of $753,000 was a result of a pre-tax income of $2,264,300 compared to a benefit for income taxes of $1,073,000 in the 2009 quarter resulting from a pre-tax loss of $2,001,512. The provision for income taxes increased in the 2010 quarter by $1,826,000, the result of a $4,265,812 increase in income (loss) before provision (benefit) for income taxes in the 2010 quarter compared to the 2009 quarter and the removal of $51,000 of the valuation allowance in the 2010 quarter on Oklahoma net operating loss carryforwards (NOLs). The effective tax rate for the 2010 and

2009 quarters were 33% and 54%, respectively. Utilization of excess percentage depletion (a permanent tax benefit) reduced taxable income a lesser proportion in the 2010 quarter compared to the 2009 quarter, resulting in a lower effective tax rate for the 2010 quarter. The reversal of $51,000 of the valuation allowance on Oklahoma NOLs reduced the effective tax rate by 2% for the 2010 quarter. For further discussion regarding excess percentage depletion and its effect on the effective tax rate, see NOTE 2: Income Taxes.

NINE MONTHS ENDED JUNE 30, 2010 COMPARED TO NINE MONTHS ENDED JUNE 30, 2009

Overview:

The Company recorded a 2010 nine month period net income of $8,383,244, or $1.00 per share, as compared to a net loss of $2,748,397, or $.33 per share, in the 2009 period. The net income was primarily due to increased oil and natural gas revenues, increased gains on derivative contracts and decreased DD&A and impairment expense, partially offset by an increase in provision for income taxes. These items are further discussed below.

Revenues:

Total revenues increased $10,877,631 or 38% for the fiscal 2010 period compared to the fiscal 2009 period. Oil and natural gas revenues increased $4,866,241 as a result of increases in average oil and natural gas prices of 50% and 33%, respectively, partially offset by decreases in oil and natural gas sales volumes of 23% and 11%, respectively. Declines in forward looking natural gas prices since September 30, 2009 resulted in a net gain on natural gas derivative contracts of $5,410,714 in the 2010 period compared to a net gain of $212,578 in the 2009 period. Lease bonus and rentals increased $875,449, largely the result of renewal of leases on a majority of the Company s non-producing mineral acreage in Arkansas which had June 2010 expiration dates. The table below outlines the Company s sales volumes and average sales prices for oil and natural gas for the nine month periods of fiscal 2010 and 2009:

	Barrels Sold	Average Price	Mcf Sold	Average Price	Mcfe Sold	Average Price
Nine months ended 6/30/10	76,325	$73.16	6,146,573	$4.46	6,604,523	$4.99
Nine months ended 6/30/09	99,149	$48.81	6,928,003	$3.36	7,522,897	$3.74

Decreased drilling activity which began in 2009 has continued through the first nine months of fiscal 2010, resulting in an expected production decrease compared to the first nine months of fiscal 2009.

Depressed natural gas prices experienced in fiscal 2009, and to some degree thus far in fiscal 2010, have resulted in fewer net well proposals to the Company. Also, the Company has been very selective, only participating as a working interest owner in proposed wells with acceptable projected rates of return. Although drilling opportunities have decreased through much of the last year, the Company does own working interests in newly completed wells which began producing during the third quarter of fiscal 2010. Production from some of these new wells is significant and is expected to contribute to the Company s natural gas production and help mitigate the current decline in production. Management expects average natural gas prices for 2010 to exceed those of 2009 and anticipates the Company s drilling activity to increase during the remainder of fiscal 2010. Drilling activity which has begun in two major plays in western Oklahoma where the Company owns mineral acreage, the Anadarko (Cana) Woodford Shale and the horizontal Granite Wash, is increasing, which also should provide additional drilling opportunities for the Company.

Gains (Losses) on Natural Gas Derivative Contracts:

The Company had a net gain of $5,410,714 in the nine months ended June 30, 2010 compared to a gain of $212,578 for the nine months ended June 30, 2009. The Company received net cash payments of $1,108,900 and $1,782,400 (realized gains) for the 2010 and 2009 periods, respectively.

Lease Operating Expenses (LOE):

LOE increased $393,701 or 7% in the 2010 period. LOE increased in the fiscal 2010 period to $.93 per Mcfe compared to $.77 per Mcfe in the 2009 period. The total LOE increase and the LOE per Mcfe increase are primarily due to increased natural gas prices which increased value based fees (primarily gathering, transportation and marketing costs). Natural gas production from the Woodford Shale and Fayetteville Shale areas continue to increase as a proportion of total production. Value based fees are charged as a percent of natural gas revenues and are significantly higher in these shale areas than like fees charged in other of the Company s production areas. The total amount of value based fees in the Woodford

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Shale and Fayetteville Shale areas typically are 15% to 20% of total natural gas revenues. Value based fees increased $1,141,473 in the 2010 period or 50%, compared to the 2009 period. Value based fees per Mcfe increased $.22 in the 2010 period or 71%, compared to the 2009 period.

Partially offsetting the increase in value based fees, LOE related to field operating costs decreased $747,772 in the 2010 period compared to the 2009 period, a 21% decrease. Field operating costs were $.39 per Mcfe in the 2010 period compared to $.44 per Mcfe in the 2009 period, an 11% decrease. These decreases are due to fewer new wells coming on line with high initial LOE, fewer well repairs made in the 2010 period compared to the 2009 period and the fiscal 2009 sale of wells in the Southeast Leedey field and the McElmo Dome Unit, thus reducing fiscal 2010 LOE.

Production Taxes:

Production taxes decreased $75,302 or 7% in the 2010 period. The decrease is the net effect of increased oil and natural gas revenues, a decrease in the overall production tax rate and unexpected production tax refunds received. The decrease in the overall production tax rate is due to a greater proportion of the Company s natural gas revenues coming from horizontal shale plays which are eligible for either production tax credits or reduced production tax rates. The net effect on production taxes of the increased oil and natural gas revenues and the lower overall production tax rate is an increase of approximately $18,000. Production tax refunds of approximately $93,000 were received on the Thomas 1-7, a deep vertical well in Washita County Oklahoma. We do not accrue for deep well production tax exemptions as the state of Oklahoma caps the refunds and proportionally allocates that amount to all qualified deep wells in the state. This makes a refund impractical to estimate.

Exploration Costs:

Exploration costs increased $1,100,180 in the 2010 period compared to the 2009 period. The Company charged approximately $375,000 to exploration costs in the 2010 period related to geological and geophysical costs paid upon the execution of a joint exploration agreement with a privately held independent operator to explore for oil in eastern Oklahoma. During the 2010 period, leasehold impairment and expired leases totaled $1,040,055 compared to $256,053 during the 2009 period, a $784,002 increase. Four exploratory dry holes incurred expenses of approximately $59,000 during the 2009 period; no exploratory dry holes were drilled during the 2010 period.

Depreciation, Depletion and Amortization (DD&A):

DD&A decreased $4,883,907 or 23% in the 2010 period. DD&A was $2.42 per Mcfe in the 2010 period compared to $2.78 per Mcfe in the 2009 period. Oil and natural gas production decreased 12% in the 2010 period accounting for approximately $2,549,000 of the DD&A decrease. The remaining DD&A decrease of approximately $2,335,000 is attributable to the $.36 decline in the DD&A rate per Mcfe. This rate declined as a result of increased oil and natural gas reserves as of June 30, 2010, as compared to June 30, 2009, and a net reduction during fiscal year 2009 of approximately $3.1 million of asset basis subject to DD&A. This asset basis reduction occurred as fiscal 2009 DD&A and impairment, combined with the basis reduction associated with assets sold, exceeded new additions to properties and equipment for oil and natural gas activities.

Provision for Impairment:

The provision for impairment decreased $2,111,763 in the 2010 period compared to the 2009 period. During the 2010 period, impairment of $12,370 was recorded on 1 field. During the 2009 period, impairment of $2,124,133 was recorded on 19 fields driven by depressed oil and natural gas prices which negatively affected the estimates of future net revenues from oil and natural gas properties.

Loss (Gain) on Asset Sales, Interest and Other:

The Company benefited $1,124,682 from the settlement of a lawsuit related to one well in western Oklahoma, payment of which was received in July 2010. The Company sold its working interest in the Keahey 1-19H well at a loss of $315,647 during fiscal 2010. Also included is a gain of $217,868 for the sale of leasehold in Roger Mills County, Oklahoma.

General and Administrative Costs (G&A):

G&A costs increased $632,392 or 17% in the 2010 period. The increase is primarily related to increases in the following expense categories: personnel $330,687, legal $125,760, board of directors $87,392 and insurance $73,635. Legal expense increased primarily due to legal costs incurred during the 2010 period on a lawsuit involving one

well in western Oklahoma, whereas no like expenses were incurred during the 2009 period. The increase in personnel expenses mainly relate to higher accrued performance bonuses based on expected improved Company performance metrics in the fiscal 2010 period compared to the 2009 period.

Income Taxes:

The fiscal 2010 period provision for income taxes of $3,257,000 was a result of a pre-tax income of $11,640,244 as compared to a benefit for income taxes of $2,278,000 in the fiscal 2009 period resulting from a pre-tax loss of $5,026,397. The provision for income taxes increased in the 2010 period by $5,535,000, the result of a $16,666,641 increase in income (loss) before provision (benefit) for income taxes in the 2010 period compared to the 2009 period offset by removal of $212,000 of the valuation allowance on Oklahoma NOLs. The effective tax rate for the 2010 and 2009 periods were 28% and 45%, respectively. Utilization of excess percentage depletion (a permanent tax benefit) reduced taxable income a lesser proportion in the 2010 period compared to the 2009 period, resulting in a lower effective tax rate for the 2010 period. The reversal of $212,000 of the valuation allowance on Oklahoma NOLs reduced the effective tax rate by 2% for the 2010 period. For further discussion regarding excess percentage depletion and its effect on the effective tax rate, see NOTE 2: Income Taxes.

CRITICAL ACCOUNTING POLICIES

Critical accounting policies are those the Company believes are most important to portraying its financial conditions and results of operations and also require the greatest amount of subjective or complex judgments by management. Judgments and uncertainties regarding the application of these policies may result in materially different amounts being reported under various conditions or using different assumptions. There have been no material changes to the critical accounting policies previously disclosed in the Company s Form 10-K for the fiscal year ended September 30, 2009.

ITEM 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company s revenue can be significantly impacted by changes in market prices for oil and natural gas. Based on the Company s fiscal 2009 production, a $.10 per Mcf change in the price received for natural gas production would result in a corresponding $911,000 annual change in revenue. A $1.00 per barrel change in the price received for oil production would result in a corresponding $128,000 annual change in revenue. Cash flows could also be impacted, to a lesser extent, by changes in the market interest rates related to the Company s credit facilities. The revolving loan bears interest at the national prime rate plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%, with an established interest rate floor of 4.50% annually. The 4.5% interest rate floor was in effect at June 30, 2010, but has subsequently been removed. At June 30, 2010, there were no amounts outstanding on the revolving loan.

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in natural gas prices. Volumes under such contracts do not exceed expected production. These arrangements cover only a portion of the Company s production and provide only partial price protection against declines in natural gas prices. These derivative contracts may expose the Company to risk of financial loss and limit the benefit of future increases in prices (Refer to NOTE 10). A change of $.10 in the forward strip prices would result in a change to gain (loss) on derivative contracts of approximately $179,000. A change of $.10 in the basis differential from Nymex to CEGT and PEPL would result in a change to gain (loss) on derivative contracts of $450,000.

Changes in crude oil and natural gas reserve estimates affect the Company s calculation of DD&A. Based on the Company s 2009 production, a $.10 change in the DD&A rate per Mcfe would result in a corresponding annual change in DD&A expense of approximately $988,000. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

ITEM 4 CONTROLS AND PROCEDURES

The Company maintains disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company s President/Chief Executive Officer and Vice President/Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The Company s disclosure controls and procedures have been designed to meet, and management believes that they do meet, reasonable assurance standards. Based

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on their evaluation as of the end of the fiscal period covered by this report, the Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the Company s disclosure controls and procedures were effective.

There were no changes in the Company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting made during the fiscal quarter or subsequent to the date the assessment was completed.

PART II OTHER INFORMATION

ITEM 6 EXHIBITS AND REPORT ON FORM 8-K

(a)	EXHIBITS	Exhibit 31.1 and 31.2	Certification under Section 302 of the Sarbanes-Oxley Act of 2002
		Exhibit 32.1 and 32.2	Certification under Section 906 of the Sarbanes-Oxley Act of 2002
(b)	Form 8-K	Dated (5/20/10), item 5.02	Appointment of Certain Officers

SIGNATURES

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

	PANHANDLE OIL AND GAS INC.
August 6, 2010 Date	/s/ Michael C. Coffman
	Michael C. Coffman, President and Chief Executive Officer
August 6, 2010	/s/ Lonnie J. Lowry
Date	Lonnie J. Lowry, Vice President and Chief Financial Officer
August 6, 2010	/s/ Robb P. Winfield
Date	Robb P. Winfield, Controller and Chief Accounting Officer

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