PANHANDLE OIL & GAS INC
Form 10-Q
May 07, 2010

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 March 31, 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 (Do not check if a smaller reporting company)	Smaller reporting company o

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 May 7, 2010: 8,311,636

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PART 1 FINANCIAL INFORMATION
PANHANDLE OIL AND GAS INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Information at March 31, 2010 is unaudited)

	March 31, 2010	September 30, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 775,963	$ 639,908
Oil and natural gas sales receivables, net of allowance for uncollectible accounts	10,276,818	7,747,557
Derivative contracts	3,316,380	
Deferred income taxes	74,900	1,934,900
Refundable production taxes	900,154	616,668
Other	138,265	68,817
Total current assets	15,482,480	11,007,850
Properties and equipment, at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	202,150,672	198,076,244
Non-producing oil and natural gas properties	10,594,556	10,332,537
Furniture and fixtures	592,877	578,460
	213,338,105	208,987,241
Less accumulated depreciation, depletion and amortization	124,460,454	112,900,027
Net properties and equipment	88,877,651	96,087,214
Investments	631,272	682,391
Refundable production taxes	305,304	772,177
Total assets	$ 105,296,707	$ 108,549,632
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 4,003,713	$ 4,810,687
Derivative contracts		1,726,901
Accrued liabilities	2,152,835	1,033,570
Total current liabilities	6,156,548	7,571,158
Long-term debt	4,945,058	10,384,722
Deferred income taxes	22,444,650	24,064,650
Asset retirement obligations	1,635,495	1,620,225
Derivative contracts	11,566	786,534

Stockholders equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued at March 31, 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	2,135,232	1,862,499
Retained earnings	70,215,861	64,507,547
	74,413,670	68,432,623
Less treasury stock, at cost; 119,866 shares at March 31, 2010 and at September 30, 2009	(4,310,280)	(4,310,280)
Total stockholders equity	70,103,390	64,122,343
Total liabilities and stockholders equity	$ 105,296,707	$ 108,549,632

(See accompanying notes)

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

	Three Months Ended March 31,		Six Months Ended March 31,	
	2010	2009	2010	2009
Revenues:				
Oil and natural gas sales	$ 12,510,995	$ 8,440,156	$ 23,321,427	$ 19,056,820
Lease bonuses and rentals	92,108	39,862	122,936	153,242
Gains (losses) on derivative contracts	4,226,309	290,545	5,629,649	683,552
Gain on asset sales, interest and other	6,439	38,398	109,590	96,458
Income of partnerships	27,472	65,054	104,224	203,645
	16,863,323	8,874,015	29,287,826	20,193,717
Costs and expenses:				
Lease operating expenses	2,177,576	1,927,325	4,484,120	3,676,468
Production taxes	449,903	340,490	804,945	747,238
Exploration costs	300,502	30,043	876,763	202,308
Depreciation, depletion and amortization	5,484,080	7,087,500	10,776,775	14,037,592
Provision for impairment	12,370	132,321	12,370	2,008,241
General and administrative	1,428,702	1,327,592	2,845,500	2,546,755
Interest expense	45,624		111,409	
	9,898,757	10,845,271	19,911,882	23,218,602
Income (loss) before provision (benefit) for income taxes	6,964,566	(1,971,256)	9,375,944	(3,024,885)
Provision (benefit) for income taxes	1,801,000	(1,026,000)	2,504,000	(1,205,000)
Net income (loss)	$ 5,163,566	$ (945,256)	$ 6,871,944	$ (1,819,885)
Basic and diluted earnings (loss) per common share (Note 3)	$ 0.61	$ (0.11)	$ 0.82	$ (0.22)
Weighted average shares outstanding:				
Common shares	8,311,636	8,300,128	8,311,636	8,300,128
Unissued, vested directors shares	110,041	96,602	102,268	95,950
	8,421,677	8,396,730	8,413,904	8,396,078
Dividends declared per share of common stock and paid in period	$ 0.07	$ 0.07	$ 0.14	$ 0.14

(See accompanying notes)
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PANHANDLE OIL AND GAS INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(Information at and for the six months ended March 31, 2010 is unaudited)
Six Months Ended March 31, 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					6,871,944			6,871,944
Dividends ($.14 per share)					(1,163,630)			(1,163,630)
Increase in deferred directors compensation charged to expense				272,733				272,733
Balances at March 31, 2010	8,431,502	$ 140,524	$ 1,922,053	$ 2,135,232	$ 70,215,861	(119,866)	$ (4,310,280)	$ 70,103,390

Six Months Ended March 31, 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					(1,819,885)			(1,819,885)
Dividends ($.14 per share)					(1,162,018)			(1,162,018)
				203,362				203,362

Increase in deferred directors compensation charged to expense								
Balances at March 31, 2009	8,431,502	$ 140,524	$ 2,090,070	$ 1,809,173	$ 66,254,701	(131,374)	$ (4,724,108)	$ 65,570,360

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

	Six months ended March 31, 2010	Six months ended March 31, 2009
Operating Activities		
Net income (loss)	$ 6,871,944	$ (1,819,885)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Unrealized (gains) losses on natural gas derivative contracts	(5,818,249)	438,448
Depreciation, depletion, amortization and impairment	10,789,145	16,045,833
Provision for deferred income taxes	240,000	(1,412,000)
Exploration costs	876,763	202,308
Net (gain) loss on sale of assets and other	(227,568)	(155,238)
Income from partnerships	(104,224)	(203,645)
Distributions received from partnerships	155,343	238,147
Directors deferred compensation expense	272,733	203,362
Cash provided by changes in assets and liabilities:		
Oil and natural gas sales receivables	(2,529,261)	8,967,404
Refundable income taxes		2,162,305
Refundable production taxes	183,387	(339,439)
Other current assets	(69,448)	(362,580)
Accounts payable	(181,418)	466,782
Income taxes payable	1,147,436	283,877
Accrued liabilities	(28,171)	196,007
Total adjustments	4,706,468	26,731,571
Net cash provided by operating activities	11,578,412	24,911,686
Investing Activities		
Capital expenditures, including dry hole costs	(5,109,510)	(30,271,588)
Proceeds from leasing of fee mineral acreage	165,589	172,429
Proceeds from sales of assets	104,858	2,000
Net cash used in investing activities	(4,839,063)	(30,097,159)
Financing Activities		
Borrowings under debt agreement	9,567,559	36,488,666
Payments of loan principal	(15,007,223)	(30,382,519)
Payments of dividends	(1,163,630)	(1,162,018)
Net cash provided by (used in) financing activities	(6,603,294)	4,944,129
Increase (decrease) in cash and cash equivalents	136,055	(241,344)
Cash and cash equivalents at beginning of period	639,908	895,708

Cash and cash equivalents at end of period	$ 775,963	$ 654,364
Supplemental Schedule of Noncash Investing and Financing Activities		
Additions to asset retirement obligations	$ 15,270	$ 156,101
Gross additions to properties and equipment	$ 4,483,954	$ 18,281,761
Net (increase) decrease in accounts payable for properties and equipment additions	625,556	11,989,827
Capital expenditures, including dry hole costs	$ 5,109,510	$ 30,271,588

(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 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 March 31, 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 (NOLs). Due to lower expected levels of intangible drilling costs to be incurred during fiscal 2010, the Company expects to be able to utilize approximately $161,000 of these Oklahoma NOLs in fiscal 2010. Therefore, the Company removed $161,000 of the Oklahoma NOL valuation allowance in the March 31, 2010 period, leaving a net valuation allowance of $117,000 representing Oklahoma NOLs the Company no longer believes are more likely than not to be utilized in future periods prior to expiration.

NOTE 3: Basic Earnings (Loss) per Share

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

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 $34,400,334 at March 31, 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, 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

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interest rate floor of 4.50% annually. The 4.50% interest rate floor was in effect at March 31, 2010. 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. If the interest rate calculation utilizing the national prime or LIBOR rate exceeds the interest rate floor, 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 March 31, 2010, the Company was in compliance with the covenants of the BOK agreement.

NOTE 5: Dividends

On February 9, 2010, the Company s Board of Directors approved payment of a $.07 per share dividend that was paid on March 9, 2010 to shareholders of record on February 22, 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 (Pinnacle Energy Services, LLC), 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 March 31, 2010 were updated, utilizing March 31, 2010 crude oil and natural gas prices ($78.83 per barrel of crude oil and $3.12 per Mcf of natural gas) held flat over the lives of the properties. The 2010 semi-annual update of crude oil and natural gas reserves utilizing price decks as of March 31, 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 crude oil and natural gas reserves of approximately 25,000 barrels and 1,051,000 Mcf, 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.

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 March 31, 2010 resulted in a charge to impairment of $12,370. As of the quarter ended March 31, 2009, the Company s test for impairment resulted in a charge to impairment of $132,321. 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 $381,982 on exploratory wells which were drilling and/or testing at March 31, 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	$ 4.01
April December, 2009	100,000 Mmbtu	CEGT	$ 3.71
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	$ 5.57
January December, 2010	50,000 Mmbtu	PEPL	$ 5.56

(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 March 31, 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	$ 5.57
January December, 2010	50,000 Mmbtu	PEPL	$ 5.56
Basis protection swaps			
January December, 2011	50,000 Mmbtu	CEGT	Nymex -$.27
January December, 2011	50,000 Mmbtu	PEPL	Nymex -$.26
January December, 2012	50,000 Mmbtu	CEGT	Nymex -$.29
January December, 2012	50,000 Mmbtu	PEPL	Nymex -$.29

(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 $3,304,814 as of March 31, 2010 and a liability of $2,513,435 as of September 30, 2009. Realized and unrealized gains and (losses) for the periods ended March 31, 2010 and 2009 are scheduled below:

Gains (losses) on natural gas derivative contracts current	Three months ended 3/31/2010	Three months ended 3/31/2009	Six months ended 3/31/2010	Six months ended 3/31/2009
Realized	$ 57,000	$ 82,800	$ (188,600)	$ 1,122,000
Increase (decrease) in fair value	4,180,875	490,285	5,043,281	(155,908)
Total	$ 4,237,875	$ 573,085	$ 4,854,681	$ 966,092

Gains (losses) on natural gas derivative contracts long-term	Three months ended 3/31/2010	Three months ended 3/31/2009	Six months ended 3/31/2010	Six months ended 3/31/2009
Realized	$	$	$	$
Increase (decrease) in fair value	(11,566)	(282,540)	774,968	(282,540)
Total	$ (11,566)	$ (282,540)	$ 774,968	$ (282,540)

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 March 31, 2010 and September 30, 2009:

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	Balance Sheet Location	3/31/2010 Fair Value	9/30/2009 Fair Value
Asset Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$ 3,316,380	$
Commodity contracts	Long-term derivative contracts		
Total Asset Derivatives (a)		$ 3,316,380	$
Liability Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$	$ 1,726,901
Commodity contracts	Long-term derivative contracts	11,566	786,534
Total Liability Derivatives (a)		$ 11,566	$ 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 six month period ended March 31, 2010, an impairment loss of $256,328 and $836,961, respectively, was charged to exploration costs 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 March 31, 2010, the Company also had additional costs of $44,174 related to expired leases and dry hole adjustments. In the quarter ended March 31, 2009, an impairment loss of $18,196 was charged to exploration costs for non-producing leases as well as additional costs of $11,847 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 March 31, 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	$	$3,304,814	$	$3,304,814

Level 2 The Company utilizes the market approach in determining the fair values of its natural gas swaps, which are corroborated by observable market data by correlation to Nymex natural gas forward curve pricing. These values are based upon, among other things, future prices and time to maturity.

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 Company s debt 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: 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. All guidance in the Codification has an equal level of authority. 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 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 $9,325,932 at March 31, 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 3/31/2010	As of 9/30/2009	Change
CURRENT ASSETS:			
Cash and cash equivalents	$ 775,963	$ 639,908	$ 136,055
Oil and natural gas sales receivables (net) **(1)**	10,276,818	7,747,557	2,529,261
Derivative contracts **(2)**	3,316,380		3,316,380
Deferred income taxes **(3)**	74,900	1,934,900	(1,860,000)
Refundable production taxes **(4)**	900,154	616,668	283,486
Other current assets	138,265	68,817	69,448
Total current assets	15,482,480	11,007,850	4,474,630
CURRENT LIABILITIES:			
Accounts payable **(5)**	4,003,713	4,810,687	(806,974)
Derivative contracts **(2)**		1,726,901	(1,726,901)
Accrued liabilities **(6)**	2,152,835	1,033,570	1,119,265
Total current liabilities	6,156,548	7,571,158	(1,414,610)
WORKING CAPITAL	$ 9,325,932	$ 3,436,692	$ 5,889,240

(1) The increase in oil and natural gas sales receivables was the result of increased oil and natural gas prices, partially offset by decreases in oil and natural gas production volumes.

(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 $3,316,380 as of March 31, 2010 due to lower forward looking natural gas prices as of March 31, 2010. The Company has made net payments relative to its derivative contracts of $188,600 during fiscal 2010.

(3) Approximately $978,000 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 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 $886,000.

(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 of approximately $460,000.

(5) Accounts payable decreased as a result of reduced drilling activity.

(6) The increase in accrued liabilities is primarily due to increased income taxes payable of approximately $1,100,000 as a result of higher income before provision for income taxes.

Cash flow provided by operating activities was $11,578,412 as of March 31, 2010 compared to $24,911,686 as of March 31, 2009, a 54% decrease. The following schedule and footnotes explain major elements of the decrease:

ANALYSIS OF CHANGE IN CASH PROVIDED BY OPERATING ACTIVITIES

	6 months ended 3/31/2010	6 months ended 3/31/2009	Change
Net income (loss)	$ 6,871,944	$ (1,819,885)	$ 8,691,829
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Unrealized gains (losses) on natural gas derivative contracts **(1)**	(5,818,249)	438,448	(6,256,697)
Depreciation, depletion, amortization and impairment **(2)**	10,789,145	16,045,833	(5,256,688)
Deferred income taxes (net) **(3)**	240,000	(1,412,000)	1,652,000
Exploration costs	876,763	202,308	674,455
Net (gain) loss on sale of assets	(227,568)	(155,238)	(72,330)
Income from partnerships	(104,224)	(203,645)	99,421
Distributions received from partnerships	155,343	238,147	(82,804)
Directors deferred compensation	272,733	203,362	69,371
Cash provided by changes in assets and liabilities:			
Oil and natural gas sales receivables **(4)**	(2,529,261)	8,967,404	(11,496,665)
Refundable income taxes **(5)**		2,162,305	(2,162,305)
Refundable production taxes	183,387	(339,439)	522,826
Other current assets	(69,448)	(362,580)	293,132
Accounts payable	(181,418)	466,782	(648,200)
Income taxes payable **(5)**	1,147,436	283,877	863,559
Accrued liabilities	(28,171)	196,007	(224,178)
Net cash provided by operating activities	$ 11,578,412	$ 24,911,686	$ (13,333,274)

(1) During the first six months of

fiscal 2010, the fair value of derivative contracts increased $5,818,249. During the first six months of fiscal 2009, the fair value of derivative contracts decreased $438,448.

(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 subject to DD&A of approximately $3.1 million 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 $2,008,241 in 2009. For further discussion related to these items, see Depreciation, Depletion and Amortization and Provision for Impairment in Management s Discussion and Analysis.

(3) The deferred income tax positive change to cash provided by operating activities of $1,652,000 resulted from a provision for deferred income taxes during the first six months of fiscal 2010 of $240,000 (on before tax income of $9,375,944) compared to a deferred income tax benefit of $1,412,000 during the first six months of fiscal 2009 (on a before tax loss of $3,024,885). 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) Through March 31, 2010, oil and natural gas sales receivables increased due to higher oil and natural gas prices; whereas, through March 31, 2009 oil and natural gas sales receivables had decreased as a result of lower oil and natural gas prices. The net change to cash provided by operating activities was a decrease of $11,496,665 as receivables collected during the fiscal 2009 period exceeded those collected during the fiscal 2010 period.

(5) During the first six months of fiscal 2010, income taxes payable increased $1,147,436; whereas, during the first six months of fiscal 2009 income taxes payable increased $283,877 resulting in a positive impact to net cash provided by operating activities of $863,559. For the six months ended March 31, 2009, refundable income taxes decreased $2,162,305 (primarily due to refund payments received of approximately $2.2 million), thus increasing net cash provided by operating activities by $2,162,305. Refundable income taxes and income taxes payable overall net effect on changes in net cash provided by operating activities is a negative effect of $1,298,746.

Additions to properties and equipment for oil and natural gas activities as of March 31, 2010 were $4,483,954 ($18,281,761 as of March 31, 2009). The Company received higher natural gas prices during the first six months of fiscal 2010 compared to the first six months of fiscal 2009, and management currently expects natural gas prices for the last six months of fiscal 2010 to exceed natural gas prices received during the last six months of fiscal 2009. Although these higher natural gas prices have not increased drilling opportunities for the Company as quickly as expected, we anticipate increased activity through the end of fiscal 2010.

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 substantial drilling opportunities. Recently, several operators have begun to focus their drilling in areas that offer liquids-rich natural gas or oil production; and, the Company has significant acreage positions in some of these areas. Since drilling activity has not increased on our acreage as quickly as anticipated, fiscal 2010 additions to properties and equipment for oil and natural gas activities is projected to be approximately $15 million, as compared to approximately $28.5 million spent during fiscal 2009.

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 six-months ended March 31, 2010, cash provided by operating activities was $11,578,412; well in excess of capital expenditures of $5,109,510. This allowed us to further reduce bank debt by $5,437,644 to $4,945,058 as of March 31, 2010. 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 increased borrowings under the Company s credit facility. The Company has availability ($30,054,942 at March 31, 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 MARCH 31, 2010 COMPARED TO THREE MONTHS ENDED MARCH 31, 2009

Overview:

The Company recorded a second quarter 2010 net income of $5,163,566, or $.61 per share, compared to a net loss of $945,256, or $.11 per share, in the 2009 quarter. The net income was due to increased oil and natural gas revenues, increased gains on derivative contracts and decreased depreciation, depletion and amortization expense, partially offset by increased provision for income taxes. These items are further discussed below.

Revenues:

Total revenues were up $7,989,308 or 90% for the 2010 quarter compared to the 2009 quarter. The revenue growth was the result of a $4,070,839 increase in oil and natural gas revenues and revenue increases of $3,935,764 related to natural gas derivative contracts. Higher oil and natural gas revenues resulted from increases in average oil and natural gas prices of

82% and 72%, respectively, partially offset by decreases in oil and natural gas sales volumes of 37% and 10%, respectively. Decreases in forward looking natural gas prices since September 30, 2009 resulted in a net gain on natural gas derivative contracts of $4,226,309 in the 2010 quarter as compared to a net gain of $290,545 in the 2009 quarter. 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 3/31/10	21,998	$74.87	1,958,166	$5.55	2,090,154	$5.99
Three months ended 3/31/09	34,744	$41.21	2,171,660	$3.23	2,380,124	$3.55

Decreased drilling activity which began in 2009 has continued through most of the first six months of fiscal 2010 resulting in an expected production decrease. The natural production decline of existing wells is currently exceeding added production from newly completed wells.

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 second 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
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
3/31/09	34,744	2,171,660	2,380,124

Gains (Losses) on Natural Gas Derivative Contracts:

The fair value of derivative contracts was $3,304,814 as of March 31, 2010 and $207,745 as of March 31, 2009. The Company had a net gain of $4,226,309 in the three months ended March 31, 2010 compared to a gain of $290,545 for the three months ended March 31, 2009. The Company received net cash payments (realized gains) under the contracts of $57,000 and $82,800 for the three months ended March 31, 2010 and 2009, respectively.

Lease Operating Expenses (LOE):

LOE increased $250,251 or 13% in the 2010 quarter. LOE per Mcfe increased from $.81 in the 2009 quarter to $1.04 in the 2010 quarter. 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 and marketing costs). Natural gas production from the Woodford Shale and Fayetteville Shale areas continue to increase as a proportion of total natural gas 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 value based fees in the Woodford Shale and Fayetteville Shale areas typically are 20% to 25% of total natural gas revenues. Value based fees increased $534,006 in the 2010 quarter or 72% compared to the 2009 quarter. Value based fees per Mcfe increased $.30 in the 2010 quarter or 97% compared to the 2009 quarter.

Partially offsetting the increase in value based fees, LOE related to field operating costs decreased $283,755 or 24% in the 2010 quarter compared to the 2009 quarter. Field operating costs per Mcfe decreased 18% from $.49 in the 2009 quarter to $.40 in the 2010 quarter. These decreases are due to fewer new wells coming on line with high initial LOE, fewer well repairs made in the 2010 quarter compared to the 2009 quarter 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 increased $109,413 or 32% in the 2010 quarter. The increase is the result of increased oil and natural gas revenues, partially offset by a decrease in the overall production tax rate as a greater proportion of the Company s natural gas revenues is coming from horizontal shale plays which are eligible for either production tax credits or reduced production tax rates.

Exploration Costs:

Exploration costs were up $270,459 in the 2010 quarter compared to the 2009 quarter. Due to the shorter timeframe before expiration of certain of the Company s non-producing leasehold, and the reassessment of risk of commercial production from such leases, non-producing leasehold was impaired $256,328 in the 2010 quarter compared to $18,196 in the 2009 quarter. Expired leases charges were $44,063 in the 2010 quarter compared to $900 in the 2009 quarter. Charges for exploratory dry holes totaled $111 during the 2010 quarter and $11,847 in the 2009 quarter.

Depreciation, Depletion and Amortization (DD&A):

DD&A decreased $1,603,420 or 23% in the 2010 quarter. DD&A per Mcfe in the 2010 quarter was $2.62 as compared to $2.98 in the 2009 quarter. Oil and natural gas production decreased 12% in the 2010 quarter accounting for approximately $863,000 of the DD&A decrease. The remaining DD&A decrease of approximately $740,000 is attributable to the $.35 decline in the DD&A rate per Mcfe. This rate declined as a result of increased oil and natural gas reserves as of March 31, 2010 compared to March 31, 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 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 during fiscal year 2009.

Provision for Impairment:

The provision for impairment decreased $119,951 in the 2010 quarter. During the 2010 quarter, impairment of $12,370 was recorded on one field. Two fields were impaired during the 2009 quarter a total of $132,321.

General and Administrative Costs (G&A):

In the 2010 quarter, G&A costs increased $101,110 or 8%. The increase is primarily related to increases (decreases) in the following expense categories: personnel $116,015, board of directors $63,750, insurance $20,866, legal ($55,479) and technical consulting ($52,067).

Income Taxes:

The 2010 quarter provision for income taxes of $1,801,000 was a result of a pre-tax income of $6,964,566 compared to a benefit for income taxes of $1,026,000 in the 2009 quarter resulting from a pre-tax loss of $1,971,256. The provision for income taxes increased in the 2010 quarter by $2,827,000, the result of an $8,935,822 increase in income (loss) before provision (benefit) for income taxes in the 2010 quarter compared to the 2009 quarter and removal of $161,000 of the valuation allowance on Oklahoma net operating loss carryforwards (NOLs). The effective tax rate for the 2010 and 2009 quarters were 26% and 52%, 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 $161,000 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.

SIX MONTHS ENDED MARCH 31, 2010 COMPARED TO SIX MONTHS ENDED MARCH 31, 2009

Overview:

The Company recorded a six month period 2010 net income of $6,871,944, or $.82 per share, as compared to a net loss of $1,819,885, or $.22 per share, in the 2009 period. The net income was due to increased oil and natural gas revenues, increased gains on derivative contracts and decreased DD&A expense, partially offset by an increase in provision for income taxes. These items are further discussed below.

Revenues:

Total revenues increased $9,094,109 or 45% for the fiscal 2010 period compared to the fiscal 2009 period. Oil and natural gas revenues increased $4,264,607 as a result of increases in average oil and natural gas prices of 58% and 35%, respectively, partially offset by decreases in oil and natural gas sales volumes of 24% and 9%, respectively. Declines in forward looking natural gas prices since September 30, 2009 resulted in a net gain on natural gas derivative contracts of $5,629,649 in the 2010 period compared to a net gain of $683,552 in the 2009 period. The table below outlines the Company s sales volumes and average sales prices for oil and natural gas for the six month periods of fiscal 2010 and 2009:

	Barrels Sold	Average Price	Mcf Sold	Average Price	Mcfe Sold	Average Price
Six months ended 3/31/10	49,452	$72.89	4,071,575	$4.84	4,368,287	$5.34
Six months ended 3/31/09	65,004	$46.14	4,485,399	$3.58	4,875,423	$3.91

Decreased drilling activity which began in 2009 has continued through most of the first six months of fiscal 2010, resulting in an expected production decline. The natural production decline of existing wells is currently exceeding production from newly completed wells.

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 second 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 fair value of derivative contracts was $3,304,814 as of March 31, 2010 and $207,745 as of March 31, 2009. The Company had a net gain of $5,629,649 in the six months ended March 31, 2010 compared to a gain of $683,552 for the six months ended March 31, 2009. The Company made net cash payments of $188,600 (realized losses) and received cash payments of $1,122,000 (realized gains) for the 2010 and 2009 periods, respectively.

Lease Operating Expenses (LOE):

LOE increased $807,652 or 22% in the 2010 period. LOE increased in the fiscal 2010 period to $1.03 per Mcfe compared to $.75 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 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 value based fees in the Woodford Shale and Fayetteville Shale areas typically are 20% to 25% of total natural gas revenues. Value based fees increased $1,226,724 in the 2010 period or 87%, compared to the 2009 period. Value based fees per Mcfe increased $.31 in the 2010 period or 107%, compared to the 2009 period.

Partially offsetting the increase in value based fees, LOE related to field operating costs decreased $419,072 in the 2010 period compared to the 2009 period, an 18% decrease. Field operating costs were $.39 per Mcfe in the 2010 period compared to $.43 per Mcfe in the 2009 period, a 9% 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 increased $57,707 or 8% in the 2010 period. The increase is the result of increased oil and natural gas revenues, partially offset by a decrease in the overall production tax rate as a greater proportion of the Company s natural gas revenues is coming from horizontal shale plays which are eligible for either production tax credits or reduced production tax rates.

Exploration Costs:

Exploration costs increased $674,455 in the 2010 period compared to the 2009 period. Due to the shorter timeframe before expiration of certain of the Company s non-producing leasehold, and the reassessment of risk of commercial production from such leases, non-producing leasehold was impaired $831,961 in the 2010 period compared to $148,024 in the 2009 period. Expired leases charges were $44,963 in the 2010 period compared to $18,190 in the 2009 period. The Company recorded a credit to exploratory dry holes of $161 during the 2010 period and a charge of $36,094 in the 2009 period.

Depreciation, Depletion and Amortization (DD&A):

DD&A decreased $3,260,817 or 23% in the 2010 period. DD&A was $2.47 per Mcfe in the 2010 period compared to $2.88 per Mcfe in the 2009 period. Oil and natural gas production decreased 10% in the 2010 period accounting for approximately $1,460,000 of the DD&A decrease. The remaining DD&A decrease of approximately $1,800,000 is attributable to the $.41 decline in the DD&A rate per Mcfe. This rate declined as a result of increased oil and natural gas reserves as of March 31, 2010, as compared to March 31, 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 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 during fiscal year 2009.

Provision for Impairment:

The provision for impairment decreased $1,995,871 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 $2,008,241 was recorded on 18 fields driven by depressed oil and natural gas prices which negatively affected the estimates of future net revenues from oil and natural gas properties.

General and Administrative Costs (G&A):

G&A costs increased $298,745 or 12% in the 2010 period. The increase is primarily related to increases (decreases) in the following expense categories: personnel $229,320, board of directors $69,930, insurance $39,109 and technical consulting ($37,257).

Income Taxes:

The fiscal 2010 period provision for income taxes of $2,504,000 was a result of a pre-tax income of $9,375,944 as compared to a benefit for income taxes of $1,205,000 in the fiscal 2009 period resulting from a pre-tax loss of $3,024,885. The provision for income taxes increased in the 2010 period by $3,709,000, the result of a $12,400,829 increase in income (loss) before provision (benefit) for income taxes in the 2010 period compared to the 2009 period and removal of $161,000 of the valuation allowance on Oklahoma NOLs. The effective tax rate for the 2010 and 2009 periods were 27% and 40%, 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 $161,000 of the valuation allowance on Oklahoma NOLs reduced the effective tax rate by 1% 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 March 31, 2010. At March 31, 2010, the Company had $4,945,058 outstanding under these facilities. A change of .5% in the rate charged would result in a change to interest expense of $24,725.

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 $270,000.

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 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 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

(a) The annual meeting of shareholders was held on March 11, 2010.

(b) Three directors were elected for three-year terms at the meeting. The directors elected and the results of voting were as follow:

	SHARES	
DIRECTORS	FOR	WITHHELD
Bruce M. Bell	4,432,030	81,417
Robert O. Lorenz	4,430,813	82,634
Robert E. Robotti	4,390,742	122,705

(c) Two proposals were also voted upon (i) a proposal to approve and adopt Panhandle Oil and Gas Inc. 2010 Restricted Stock Plan, (ii) a proposal to ratify the appointment of Ernst & Young, LLP as our independent registered public accounting firm for the fiscal year ending September 30, 2010.

	FOR	SHARES WITHHELD	ABSTAINING
Proposal (i)	3,703,028	719,456	90,963
Proposal (ii)	6,051,152	42,350	31,323

With respect to proposal (i), no shares have been awarded under the 2010 Restricted Stock Plan as of May 7, 2010.

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 (3/15/10), item 5.02	Appointment of Certain Officers
	Dated (3/15/10), item 5.07	Submission of Matters to a Vote of Security Holders

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.

May 7, 2010
Date

/s/ Michael C. Coffman

Michael C. Coffman, President and
Chief Executive Officer

May 7, 2010
Date

/s/ Lonnie J. Lowry

Lonnie J. Lowry, Vice President
and Chief Financial Officer

May 7, 2010
Date

/s/ Robb P. Winfield

Robb P. Winfield, Controller
and Chief Accounting Officer