PANHANDLE OIL & GAS INC
Form 10-Q
May 08, 2009

Table of Contents

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, 2009

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 filedby 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 is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (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 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 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, 2009: 8,300,128

INDEX

Table of Contents

PART 1 FINANCIAL INFORMATION

Item 1 Condensed Consolidated Financial Statements

PANHANDLE OIL AND GAS INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Information at March 31, 2009 is unaudited)

	March 31, 2009	September 30, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 654,364	$ 895,708
Oil and natural gas sales receivables (net)	8,215,724	17,183,128
Short-term derivative contracts	490,285	646,193
Refundable income taxes		2,162,305
Other	970,379	217,691
Total current assets	10,330,752	21,105,025
Properties and equipment, at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	191,960,261	175,727,196
Non-producing oil and natural gas properties	11,110,912	11,216,103
Other	542,596	491,321
	203,613,769	187,434,620
Less accumulated depreciation, depletion and amortization	101,670,052	87,661,433
Net properties and equipment	101,943,717	99,773,187
Investments	701,812	736,314
Other	341,988	392,657
Total assets	$ 113,318,269	$ 122,007,183
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 4,374,520	$ 15,897,565
Accrued liabilities	804,463	608,456
Income taxes payable	283,877	
Total current liabilities	5,462,860	16,506,021
Long-term debt	15,810,247	9,704,100
Deferred income taxes	24,531,750	25,943,750
Asset retirement obligations	1,660,512	1,504,411
Long-term derivative contracts	282,540	

Stockholders equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued at March 31, 2009 and at September 30, 2008	140,524	140,524
Capital in excess of par value	2,090,070	2,090,070
Deferred directors compensation	1,809,173	1,605,811
Retained earnings	66,254,701	69,236,604
	70,294,468	73,073,009
Less treasury stock, at cost; 131,374 shares at March 31, 2009 and at September 30, 2008	(4,724,108)	(4,724,108)
Total stockholders equity	65,570,360	68,348,901
Total liabilities and stockholders equity	$ 113,318,269	$ 122,007,183

(See accompanying notes)

(1)

Table of Contents

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

	Three Months Ended March 31,		Six Months Ended March 31,	
	2009	2008	2009	2008
Revenues:				
Oil and natural gas sales	$ 8,440,156	$ 14,909,601	$ 19,056,820	$ 28,135,695
Lease bonuses and rentals	39,862	67,864	153,242	78,310
Gains (losses) on derivative contracts	290,545	(2,368,313)	683,552	(2,104,527)
Gain on asset sales, interest and other	38,398	32,361	96,458	84,755
Income of partnerships	65,054	105,709	203,645	256,792
	8,874,015	12,747,222	20,193,717	26,451,025
Costs and expenses:				
Lease operating expenses	1,927,325	1,453,518	3,676,468	2,798,419
Production taxes	340,490	926,355	747,238	1,755,959
Exploration costs	30,043	151,750	202,308	361,731
Depreciation, depletion and amortization	7,087,500	4,448,543	14,037,592	8,705,153
Provision for impairment	132,321	225,997	2,008,241	348,006
General and administrative	1,327,592	1,229,778	2,546,755	2,826,823
Interest expense				44,346
	10,845,271	8,435,941	23,218,602	16,840,437
(Loss) income before (benefit) provision for income taxes	(1,971,256)	4,311,281	(3,024,885)	9,610,588
(Benefit) provision for income taxes	(1,026,000)	1,480,000	(1,205,000)	3,299,000
Net (loss) income	$ (945,256)	$ 2,831,281	$ (1,819,885)	$ 6,311,588
(Loss) earnings per common share (Note 4)	$ (0.11)	$ 0.33	$ (0.22)	$ 0.74
Weighted average shares outstanding:				
Common shares	8,300,128	8,431,502	8,300,128	8,431,502
Unissued, vested directors shares	96,602	85,057	95,950	79,592
	8,396,730	8,516,559	8,396,078	8,511,094
Dividends declared per share of common stock and paid in period	$ 0.07	$ 0.07	$ 0.14	$ 0.14

(See accompanying notes)
(2)

Table of Contents

PANHANDLE OIL AND GAS INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(Information at and for the six months ended March 31, 2009 is unaudited)
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)
Increase in deferred directors compensation charged to expense				203,362				203,362
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)
(3)

Table of Contents

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

	Six months ended March 31, 2009	2008
Operating Activities		
Net (loss) income	$ (1,819,885)	$ 6,311,588
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Gain, net, on sale of assets	(155,238)	(84,279)
Income of partnerships	(203,645)	(256,792)
Exploration costs	202,308	361,731
Depreciation, depletion and amortization	14,037,592	8,705,153
Provision for impairment	2,008,241	348,006
Deferred income taxes	(1,412,000)	2,086,000
Distributions received from partnerships	238,147	297,864
Directors deferred compensation expense	203,362	195,952
Cash provided by changes in assets and liabilities:		
Oil and natural gas sales receivables	8,967,404	(4,707,925)
Derivative contracts	438,448	2,205,527
Refundable income taxes	2,162,305	
Other current assets	(752,688)	14,975
Other non-current assets	50,669	
Accounts payable	466,782	199,456
Accrued liabilities	196,007	363,250
Income taxes payable	283,877	317,295
Total adjustments	26,731,571	10,046,213
Net cash provided by operating activities	24,911,686	16,357,801
Investing Activities		
Capital expenditures, including dry hole costs	(30,271,588)	(16,095,211)
Proceeds from leasing of fee mineral acreage	172,429	98,178
Proceeds from asset sales	2,000	6,420
Net cash used in investing activities	(30,097,159)	(15,990,613)
Financing Activities		
Borrowings under credit facility	36,488,666	17,162,975
Payments on credit facility	(30,382,519)	(16,705,064)
Payments of dividends	(1,162,018)	(1,180,410)
Net cash provided by (used in) financing activities	4,944,129	(722,499)
Decrease in cash and cash equivalents	(241,344)	(355,311)
Cash and cash equivalents at beginning of period	895,708	989,360

Cash and cash equivalents at end of period	$	654,364	$	634,049
Supplemental Schedule of Noncash Investing and Financing Activities				
Additions to asset retirement obligations	$	156,101	$	
Net decrease in accounts payable for properties and equipment additions	$	11,989,827	$	2,157,999

(See accompanying notes)
(4)

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 2008 Annual Report on Form 10-K.

NOTE 2: Income Taxes

The Company s benefit or provision for income taxes (both federal and state) differs from the statutory rate primarily due to estimated excess percentage depletion and a valuation allowance ($278,000) placed on certain state tax net operating loss carryforwards (NOLs) the Company no longer believes are more likely than not to be utilized in future periods prior to expiration. This estimate will be updated throughout the year until finalized with the detail well-by-well calculation at year-end. Thus, it is subject to change in the near term. The effect of the excess percentage depletion when a benefit for income taxes is recorded, is to increase the effective tax rate (as is the case as of March 31, 2009), while the effect is to decrease the effective tax rate when a provision for income taxes is recorded. The benefit of excess percentage depletion and the provision related to the state NOL valuation allowances are not directly related to the amount of a recorded loss or income. Accordingly, in cases where a recorded loss or income is relatively small, the proportional effect of the excess percentage depletion and the state NOL valuation allowances on the effective tax rate may become significant.

On October 1, 2007, the Company adopted the provisions of FIN No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes* (SFAS 109). FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Company and its subsidiary file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, the Company is no longer subject to U.S. federal, state, and local income tax examinations for years prior to fiscal year 2006.

NOTE 3: Stock Repurchase Program

On May 28, 2008 and July 29, 2008, the Company announced that its Board of Directors had approved stock repurchase programs to purchase up to $2,000,000 and $3,000,000, respectively, of the Company s common stock. The shares are held in treasury and are accounted for using the cost method. Total shares purchased under the two programs were 139,014. On September 30, 2008, 7,640 treasury shares were contributed to the Company s ESOP on behalf of the ESOP participants, leaving 131,374 shares held in treasury as of March 31, 2009.

NOTE 4: (Loss) Earnings per Share

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

NOTE 5: Long-term Debt

Effective February 3, 2009, the Company amended its revolving credit facility with Bank of Oklahoma (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 and change the maturity date to October 31, 2011. 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%,

(5)

with an established interest rate floor of 4.50% annually. The 4.50% interest rate floor has been in effect since the amendment. 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 reserves.

NOTE 6: Dividends

On December 10, 2008, the Company s Board of Directors approved payment of a $.07 per share dividend that was paid on March 6, 2009 to shareholders of record on February 23, 2009.

NOTE 7: 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 8: Oil and Natural Gas Reserves

The estimation of crude oil and natural gas reserves affect 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 geologists, 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. DD&A was calculated in the quarter ended March 31, 2009 based on the 2009 semi-annual update of crude oil and natural gas reserve estimates utilizing March 31, 2009 crude oil and natural gas pricing ($46.93 per barrel for crude oil and $2.47 per Mcf for natural gas) held flat over the life of the properties. The 2009 semi-annual update of crude oil and natural gas reserves was negatively impacted by the low crude oil and natural gas prices which reduced the economic lives of the Company s properties resulting in lower overall reserve volumes and accelerated DD&A on the properties. The low prices resulted in downward revisions to crude oil and natural gas reserves of approximately 132,000 barrels and 7,104,000 Mcf, respectively. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

NOTE 9: 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. To assess assets for impairment as of March 31, 2009, projected future crude oil prices (from $49.81 per barrel to $75.27 per barrel) and natural gas prices (from $3.06 per MCF to $6.63 per MCF) were used to estimate crude oil and natural gas reserves. The assessment resulted in an impairment provision of $132,321 for the March 31, 2009 quarter. A further reduction in oil and natural gas prices or a decline in reserve volumes would likely lead to additional impairment in future periods that may be material to the Company.

NOTE 10: Capitalized Costs

Oil and natural gas properties include costs of $781,013 on exploratory wells which were drilling and/or testing at March 31, 2009. The Company is expecting to have evaluation results on these wells within the next six months.

Table of Contents

NOTE 11: Derivatives

The Company accounts for its derivative contracts under Financial Accounting Standards Board Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, (SFAS No. 133). Under the provision of SFAS No. 133, the Company is required to recognize all derivative instruments as either assets or liabilities in the consolidated balance sheet at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivatives designated as cash flow hedges, for which there were none at March 31, 2009, and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Hedge effectiveness is required to be measured at least quarterly based on relative changes in fair value between the derivative contract and hedged item during the period of hedge designation. The ineffective portion of a derivative s change in fair value is recognized in current earnings. For derivative instruments not designated as hedging instruments, the change in fair value is recognized in earnings during the period of change as a change in derivative fair value.

In accordance with FASB Interpretation No. 39, 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 impact of netting was immaterial for all periods presented.

Historically, the Company has entered in costless collar arrangements, but currently has entered in fixed swap contracts, both of which were intended to reduce the Company s exposure to short-term fluctuations in the price of natural gas. Collar contracts set a fixed floor price and a fixed ceiling price and provide for payments to the Company if the basis adjusted price falls below the floor or require payments by the Company if the basis adjusted price rises above the ceiling. Fixed swap contracts set a fixed price and provide for payments to the Company if the basis adjusted price is below the fixed price, or require payments by the Company if the basis adjusted price is above the fixed price. These arrangements cover only a portion of the Company s natural gas production and provide only partial price protection against declines in natural gas prices. These economic hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in prices. The derivative instruments will settle based on the prices below which are tied to Centerpoint Energy Gas Transmission s East pipeline in Oklahoma.

Derivative contracts in place as of March 31, 2009
(prices below reflect the Company s net price from Centerpoint
Gas Transmission s East pipeline in Oklahoma)

Contract period	Production volume covered per month	Fixed price
March December, 2009	60,000 mmbtu	$4.010
April December, 2009	100,000 mmbtu	$3.710
May December, 2009	70,000 mmbtu	$3.615
January December, 2010	50,000 mmbtu	$5.050
January December, 2010	100,000 mmbtu	$5.015

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 under SFAS No. 133 to permit these derivative contracts to be accounted for as cash flow hedges. The Company s net fair value of derivative contracts was an asset of $207,745 as of March 31, 2009 and an asset of $646,193 as of September 30, 2008. Realized and unrealized gains for the periods ended March 31, 2009 and March 31, 2008 are scheduled below:

Table of Contents

Gains (losses) on natural gas derivative contracts - current	Three months ended 3/31/2009	Three months ended 3/31/2008	Six months ended 3/31/2009	Six months ended 3/31/2008
Realized	$ 82,800	$ 39,600	$ 1,122,000	$ 101,000
Increase (decrease) in fair value	490,285	(2,407,913)	(155,908)	(2,205,527)
Total	$ 573,085	$ (2,368,313)	$ 966,092	$ (2,104,527)

Losses on natural gas derivative contracts - long-term	Three months ended 3/31/2009	Three months ended 3/31/2008	Six months ended 3/31/2009	Six months ended 3/31/2008
Realized	$	$	$	$
Decrease in fair value	(282,540)		(282,540)	
Total	$ (282,540)	$	$ (282,540)	$

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

NOTE 12: Exploration Costs

Certain non-producing leases which have expired or which have no future plans of development with an aggregate carrying value of $166,214 were fully impaired and charged to exploration costs in the quarter ended March 31, 2009, along with $36,094 related to exploratory dry holes. In the quarter ended March 31, 2008, $371,129 was charged to exploration costs for non-producing leases which had expired or which had no future plans of development, slightly offset by small credits on previously recorded exploratory dry holes.

NOTE 13: Fair Value Measurements

Effective October 1, 2008, the Company adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements for its financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities. The Company has only partially applied SFAS No. 157 and will delay full application for nonfinancial assets and liabilities until the Company s fiscal year beginning October 1, 2009 as permitted by FSP 157-2. The Company is currently assessing the impact that full application for nonfinancial assets and liabilities will have on its financial position, results of operations and cash flows.

SFAS 157 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 and have the highest priority. 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 and have the lowest priority. 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, 2009.

Table of Contents

	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	$	$207,745	$	$207,745

Level 2 Fair Value Measurements

Derivatives. The fair values of the Company s natural gas swaps are corroborated by observable market data by correlation to Nymex pricing. These values are based upon, among other things, future prices and time to maturity.

Level 3 Fair Value Measurements

Derivatives. The fair values of the Company s derivatives, excluding natural gas swaps, are based on estimates provided by its respective counterparty and reviewed internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility and time to maturity.

A reconciliation of the Company s assets classified as Level 3 measurements is presented below.

	Derivatives
Balance of Level 3 as of October 1, 2008	$ 646,193
Total gains or losses (realized/unrealized):	
Included in earnings	393,007
Included in other comprehensive income (loss)	
Purchases, issuances and settlements	(1,039,200)
Transfers in and out of Level 3	
Balance of Level 3 as of March 31, 2009	$

NOTE 14: New Accounting Pronouncements

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. Since the Company has not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on its financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. This statement was adopted effective January 1, 2009 and will not have a material impact on the Company s financial disclosures.

In December 2008, the SEC released Final Rule, *Modernization of Oil and Gas Reporting*. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The new disclosure requirements are effective for registration statements filed on or after

January 1, 2010, and for annual reports on Forms 10-K and 20-F for fiscal years ending on or after December 31, 2009. The Company is currently assessing the impact that adoption of this rule will have on its financial 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.

Table of Contents

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 2009 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 2008 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

At March 31, 2009, the Company had positive working capital of $4,867,892, as compared to positive working capital of $4,599,004 at September 30, 2008. The increase in working capital resulted from a large decrease in accounts payable, mostly offset by a large decrease in oil and natural gas sales receivables and a decrease in refundable income taxes. Significantly lower oil and natural gas prices in fiscal 2009 have resulted in decreased drilling activity, helping reduce the Company s accounts payable. A substantial amount of the payments made for capital expenditures thus far in 2009 are for wells committed to, or which began drilling in fiscal 2008. Likewise, lower sales prices received have reduced the Company s receivables for oil and natural gas sales. Refundable income taxes declined as the Company s fiscal 2008 refund due was received during the quarter ended March 31, 2009.

Although the Company recorded a loss for the six months ended March 31, 2009, operating cash flow increased by 52% over the comparable period in fiscal 2008. During the first six months of fiscal 2009 as compared to fiscal 2008, collection of oil and natural gas sales receivables increased and after adding back increased non-cash items of depreciation, depletion and amortization and provision for impairment operating cash flow increased to $24,911,686. Additions to properties and equipment for oil and natural gas activities during the 2009 period were $18,281,761 ($13,937,212 in the 2008 period). Additions to properties and equipment are distinct from capital expenditures in that these additions include capital expenditures and net decrease (increase) in accounts payable for properties and equipment additions as reflected on the Statements of Cash Flows; therefore, additions to properties and equipment represent amounts recorded in the period, whereas capital expenditures represent amounts paid in the period. Management expects oil and natural gas prices to remain low throughout the remainder of fiscal 2009, resulting in declines in both operating cash flows and drilling activity, which will also reduce property and equipment additions for oil and natural gas activities. Low oil and natural gas prices are having a negative impact on drilling activity on the Company s mineral and leasehold acreage, and not being the operator of any of its oil and natural gas properties makes it extremely difficult for the Company to predict additions to properties and equipment with certainty. However, based on management s assessment of current conditions, fiscal 2009 additions to property and equipment for oil and natural gas activities are projected to be approximately $30,000,000; whereas fiscal 2008 property and equipment for oil and natural gas activities additions were approximately $53,000,000.

The industry-wide decline in drilling activity has also created downward pressure on the costs for drilling rigs, well equipment, and well services, which is expected to reduce the overall costs of drilling and completing wells. As lower oil and natural gas prices continue to put downward pressure on drilling activity, and resulting production declines eventually occur, natural gas prices are expected to increase in late calendar 2009 to early 2010.

The Company historically funded capital additions, overhead costs and dividend payments primarily from operating cash flow. However, due to recent sharp decreases in oil and natural gas prices and the increased expenditures for drilling in the last two years, the Company has utilized its revolving line-of-credit facility to help fund these expenditures. The Company s strategy to minimize significant increases in borrowings will be to reduce its working interest participation in certain large ownership wells or by simply taking a no cost royalty interest in certain wells. By doing so, the Company reduces its capital expenditures and thereby limits borrowings, but still receives the benefit of a relatively high net revenue interest in the wells. Even with this strategy, and given current drilling activity, temporary moderate increases in borrowing can occur while the Company awaits the receipt of first revenues (which normally is 4 to 6 months after production begins) on recently completed wells. The Company currently has several wells that have been recently completed which will provide significant cash flow during both the third and fourth quarters of fiscal 2009 as the first payments on these wells are received. Debt levels should remain reasonably stable through the remainder of fiscal 2009 as these first revenues are received and the

(10)

---

effects of the managed drilling activity reduces cash expenditures. The Company has substantial availability under its restructured 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). The Company believes its borrowing availability could be increased by placing more of the Company s properties as security under the revolving credit facility.

RESULTS OF OPERATIONS

THREE MONTHS ENDED MARCH 31, 2009 COMPARED TO THREE MONTHS ENDED MARCH 31, 2008

Overview:

The Company recorded a second quarter 2009 net loss of $945,256, or $.11 per share, as compared to a net income of $2,831,281 or $.33 per share in the 2008 quarter. The main contributing factors to the recorded loss for the period are decreased revenue due to depressed oil and natural gas prices and increased depreciation, depletion and amortization expense resulting from decreased oil and natural gas reserves. See Note 8 and discussion under Depreciation, Depletion and Amortization heading on page 12 regarding pricing used to calculate oil and natural gas reserves utilized to determine depreciation, depletion and amortization.

Revenues:

Total revenues decreased $3,873,207 or 30% for the 2009 quarter. The decrease was the result of a $6,469,445 decrease in oil and natural gas sales partially offset by revenue increases of $2,658,858 related to natural gas derivative contracts. Lower revenues from oil and natural gas sales resulted from a decrease of 58% in natural gas sales prices to $3.23 per mcf and a decrease of 57% in oil sales prices to $41.21. Although sales prices steeply declined, the negative effect on revenues was mitigated by increases in both oil and natural gas sales volumes of 7% and 42%, respectively. The Company recorded gains on natural gas derivative contracts in the fiscal 2009 quarter of $290,545 as compared to losses of $2,368,313 during the fiscal 2008 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 2009 and 2008:

	BARRELS SOLD	AVERAGE PRICE	MCF SOLD	AVERAGE PRICE	MCFE SOLD	AVERAGE PRICE
Three months ended 3/31/09	34,744	$41.21	2,171,660	$3.23	2,380,124	$3.55
Three months ended 3/31/08	32,399	$95.18	1,533,363	$7.71	1,727,757	$8.63

The increases in sales volumes are a result of successful drilling in the Company s core areas of the southeast Oklahoma Woodford Shale, the Fayetteville Shale in Arkansas and the Anadarko Basin in western Oklahoma where the Company participates in multiple plays. Contributing to the increased sales volumes, several new wells came on line during the fiscal 2009 quarter in these core areas. However, drilling in all of these areas has declined substantially and expectations are that the Company will see fewer wells coming on line during the remaining six months of fiscal 2009. This will limit the potential for sales volume increases during the last two quarters of fiscal 2009.

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

Quarter ended	Barrels Sold	MCF Sold	MCFE Sold
3/31/09	34,744	2,171,660	2,380,124
12/31/08	30,260	2,313,739	2,495,299
9/30/08	31,375	1,995,333	2,183,583
6/30/08	31,907	1,788,462	1,979,904
3/31/08	32,399	1,533,363	1,727,757

Gains (Losses) on Natural Gas Derivative Contracts:

The Company s fair value of derivative contracts was $207,745 as of March 31, 2009 and $-0- as of December 31, 2008. The Company had a net gain of $290,545 in the three months ended March 31, 2009 compared to a loss of $2,368,313 for the three months ended March 31, 2008. The Company received cash payments under the contracts of $82,800 and $39,600 (realized gains) for the three months ended March 31, 2009 and March 31, 2008, respectively.

Lease Operating Expenses (LOE):

LOE increased $473,807 or 33% in the 2009 quarter. LOE per mcfe decreased to $.81 per mcfe in the 2009 quarter, as compared to $.84 per mcfe in the 2008 quarter. The accumulation of new wells which have come on line during the last year has resulted in an overall increase in LOE. The decrease on a per mcfe basis is due to the decrease in natural gas sales prices resulting in lower value based fees (primarily gathering and marketing costs) which are charged as a percent of natural gas sales, combined with declining prices for field services and supplies.

Production Taxes:

Production taxes decreased $585,865 or 63% in the 2009 quarter as compared to the 2008 quarter. The decline in production tax expense is the result of a 43% decrease in oil and natural gas sales and production tax credits on horizontal wells drilled in the southeast Oklahoma Woodford Shale. The state of Oklahoma offers a refund on horizontally drilled wells of nearly all production taxes paid for the first four years of production or until well payout occurs, whichever comes first. The result is a decrease in the severance tax rate as a percentage of oil and natural gas sales from 6.2% in the 2008 quarter to 4.0% in the 2009 quarter. Horizontally drilled wells coming on line in the Woodford Shale (all of which qualify for the production tax credits) have become a more significant part of the Company s production, thus production tax expense as a percentage of oil and natural gas sales has continued to decline.

Exploration Costs:

Exploration costs decreased $121,707 or 80% in the 2009 quarter as compared to the 2008 quarter. The decrease is primarily related to a $138,641 decrease in leasehold expiration and abandonment costs in the 2009 quarter as compared to the 2008 quarter. One dry hole was recorded in the 2009 quarter at a cost of approximately $12,000.

Depreciation, Depletion and Amortization (DD&A):

DD&A increased $2,638,957 or 59% in the 2009 quarter. DD&A per mcfe in the 2009 quarter was $2.98 as compared to $2.57 in the 2008 quarter. The overall increase is the combined result of increased production in the 2009 quarter over the 2008 quarter and decreased oil and natural gas reserves. New wells that have come on line in the past year (most of which were higher cost horizontally drilled wells in the southeast Oklahoma Woodford Shale and the Arkansas Fayetteville Shale) have significantly increased oil and natural gas sales volumes. Low oil and natural gas prices (non-escalated prices for oil and natural gas of $46.93 and $2.47, respectively) used in the most recent reserve study reduced the economic lives of the Company s properties resulting in marginally lower reserve volumes and accelerated DD&A taken on the properties. The increased DD&A per mcfe is the result of the lower reserve volumes which create a higher DD&A rate per mcfe, and the higher cost horizontally drilled wells which have come on line in the past year.

Provision for Impairment:

The provision for impairment decreased $93,676 in the 2009 quarter. In the 2009 quarter two fields were impaired a total of $132,321 as compared to the 2008 quarter which incurred impairment on four fields totaling $225,997.

General and Administrative Costs (G&A):

G&A costs increased $97,814 or 8% in the 2009 quarter. The increase is mostly comprised of increased personnel related expenses of approximately $50,000, increased legal fees of approximately $30,000 and increased consulting fees of approximately $9,000.

Income Taxes:

The 2009 quarter incurred a benefit for income taxes of $1,026,000 as a result of a pre-tax loss of $1,971,256 as compared to a provision for income taxes of $1,480,000 in the 2008 quarter as a result of pre-tax income of $4,311,281. The resulting effective tax benefit rate in the 2009 quarter was 52% as compared to an effective tax provision rate of 34% in the 2008 quarter. The Company s utilization of excess percentage depletion (which is a permanent tax benefit) increased the tax benefit in the 2009 quarter, whereas it decreased the provision for income taxes in the 2008 quarter. The effect of this permanent tax benefit is that the effective tax rate is increased when recording a benefit for income taxes as in the fiscal 2009 quarter, while reducing the effective tax rate when recording a provision for income taxes as in the fiscal 2008 quarter. The benefit of excess percentage depletion is not directly related to the amount of a recorded loss or income. Accordingly, in cases where a recorded loss or income is relatively small, the proportional effect of the excess percentage depletion on the effective tax rate may become significant. Further, in the quarter ended March 31, 2009, with the decline in product prices and

(12)

Table of Contents

forecasted loss in fiscal 2009, the Company established a valuation allowance on certain state tax net operating loss carryforwards (NOLs) for which the Company no longer believes are more likely than not to be realized prior to expiration. This reduced the benefit recognized during the respective quarter by $278,000.

SIX MONTHS ENDED MARCH 31, 2009 COMPARED TO SIX MONTHS ENDED MARCH 31, 2008

Overview:

The Company recorded a six month period 2009 net loss of $1,819,885, or $.22 per share, as compared to a net income of $6,311,588 or $.74 per share in the 2008 period.

Revenues:

Total revenues decreased $6,257,308 or 24% for the fiscal 2009 period as compared to the fiscal 2008 period. Lower revenues from oil and natural gas sales resulted from a 49% decrease in natural gas sales prices to $3.58 per mcf and a 49% decrease in oil sales prices to $46.14 per bbl. Although prices steeply declined, an increase in natural gas sales volumes of 43% partially offset the negative effect on revenues. The Company recorded gains on natural gas derivative contracts in the fiscal 2009 period of $683,552 as compared to losses of $2,104,527 during the fiscal 2008 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 2009 and 2008:

	BARRELS SOLD	AVERAGE PRICE	MCF SOLD	AVERAGE PRICE	MCFE SOLD	AVERAGE PRICE
Six months ended 3/31/09	65,004	$46.14	4,485,399	$3.58	4,875,423	$3.91
Six months ended 3/31/08	69,120	$90.52	3,144,243	$6.96	3,558,963	$7.91

The increases in sales volumes are a result of successful drilling in the Company s core areas of the southeast Oklahoma Woodford Shale, the Fayetteville Shale in Arkansas and the Anadarko Basin in western Oklahoma where the Company has multiple plays. Contributing to the increased sales volumes, several new wells came on line during fiscal 2009 in these core areas. However, drilling in all of these areas has declined substantially and expectations are that the Company will see fewer wells coming on line during the remaining six months of fiscal 2009. This will limit the potential for sales volume increases during the last two quarters of fiscal 2009.

Gains (Losses) on Natural Gas Derivative Contracts:

The Company s fair value of derivative contracts was $207,745 as of March 31, 2009 and $646,193 as of September 30, 2008. The Company had a net gain of $683,552 in the six months ended March 31, 2009 compared to a loss of $2,104,527 for the six months ended March 31, 2008. The Company received cash payments of $1,122,000 and $101,000 (realized gains) for the 2009 and 2008 periods, respectively.

Lease Operating Expenses (LOE):

LOE increased $878,049 or 31% in the 2009 period as compared to the 2008 period. LOE per mcfe decreased in the fiscal 2009 period to $.75 per mcfe, as compared to $.79 per mcfe in the 2008 period. The accumulation of new wells which have come on line during the last year has resulted in an overall increase in LOE. The decrease on a per mcfe basis is due to the decrease in natural gas sales prices resulting in lower value based fees (primarily gathering and marketing costs) which are charged as a percent of natural gas sales, combined with declining prices for field services and supplies.

Production Taxes:

Production taxes decreased $1,008,721 or 57% in the 2009 period as compared to the 2008 period. The decline in production tax expense is the result of a 32% decrease in oil and natural gas sales and production tax credits on horizontal wells drilled in the southeast Oklahoma Woodford Shale. The state of Oklahoma offers a refund on horizontally drilled wells of nearly all production taxes paid for the first four years of production or until well payout occurs, whichever comes first. The result is a decrease in the severance tax rate as a percentage of oil and natural gas sales from 6.2% in the 2008 period to 3.9% in the 2009 period.

Table of Contents

Exploration Costs:

Exploration costs decreased $159,423 or 44% in the 2009 period as compared to the 2008 period. The decrease is primarily related to a decrease in leasehold expiration and abandonment costs in the 2009 period as compared to the 2008 period of approximately $205,000. Two dry holes were recorded in the 2009 period at a cost of approximately $36,000; no dry holes were recorded in the fiscal 2008 period.

Depreciation, Depletion and Amortization (DD&A):

DD&A increased $5,332,439 or 61% in the 2009 period as compared to the 2008 period. DD&A was $2.88 per mcfe in the 2009 period as compared to $2.45 per mcfe in the 2008 period. The overall increase is the result of increased production in the 2009 period over the 2008 period and higher DD&A per mcfe. The increase in the DD&A per mcfe is due to new wells that have come on line during the past year and decreased oil and natural gas reserves. New wells that have come on line in the past year (most of which were higher cost horizontally drilled wells in the southeast Oklahoma Woodford Shale and the Arkansas Fayetteville Shale) have significantly increased oil and natural gas sales volumes on which DD&A is calculated. Low oil and natural gas prices (non-escalated prices for oil and natural gas of $46.93 and $2.47, respectively) used in the most recent reserve study reduced the economic lives of the Company s properties resulting in lower overall reserve volumes and accelerated DD&A taken on the properties. The increased DD&A per mcfe is the result of the lower reserve volumes which create a higher DD&A rate per mcfe, and the higher cost horizontally drilled wells which have come on line in the past year.

Provision for Impairment:

The provision for impairment increased $1,660,235 in the 2009 period as compared to the 2008 period. Driven by depressed oil and natural gas prices, impairment was recorded on 18 fields during the 2009 period in the amount of $2,008,241. Two of the fields accounted for $1,729,034 of the impairment, one field in Wheeler County, Texas consisting of one deep well (drilled in 2006 and had mechanical issues during completion which dramatically increased costs) was impaired $1,070,129 and one mature field in Beckham County, Oklahoma principally consisting of wells drilled in 2006 and prior was impaired $658,905. The Company did not incur any impairment in the three primary areas of operation (Woodford Shale area, Fayetteville Shale area and Dill City project). During the 2008 period, six fields were impaired a total of $341,482.

General and Administrative Costs (G&A):

G&A costs decreased $280,068 or 10% in the 2009 period as compared to the 2008 period due to decreased personnel related costs of approximately $393,000, which included a decrease in employee bonus costs of approximately $500,000 in the 2009 period (the result of beginning to ratably accrue for estimated 2008 annual employee bonuses during the 2008 fiscal period due to specific bonus performance criteria being established plus recording the full 2007 annual discretionary bonuses approved and paid during the 2008 fiscal period), partially offset by increases in legal fees of approximately $55,000.

Income Taxes:

The fiscal 2009 period incurred a benefit for income taxes of $1,205,000 as a result of a pre-tax loss of $3,024,885 as compared to a provision for income taxes of $3,299,000 in the fiscal 2008 period as a result of pre-tax income of $9,610,588. The resulting effective tax benefit rate in the fiscal 2009 period was 40% as compared to an effective tax provision rate of 34% in the fiscal 2008 period. The Company s utilization of excess percentage depletion (which is a permanent tax benefit) increased the tax benefit in the fiscal 2009 period, whereas it decreased the provision for income taxes in the fiscal 2008 period. The effect of this permanent tax benefit is that the effective tax rate is increased when recording a benefit for income taxes as in the fiscal 2009 period, while reducing the effective tax rate when recording a provision for income taxes as in the fiscal 2008 period. The benefit of excess percentage depletion is not directly related to the amount of a recorded loss or income. Accordingly, in cases where a recorded loss or income is relatively small, the proportional effect of the excess percentage depletion on the effective tax rate may become significant. In the six months ended March 31, 2009, with the decline in product prices and forecasted loss in fiscal 2009, the Company established a valuation allowance on certain state tax net operating loss carryforwards (NOLs) for which the Company no longer believes are more likely than not to be realized prior to expiration. This reduced the benefit recognized during the respective period by $278,000.

CRITICAL ACCOUNTING POLICIES

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by the Company generally do not change the Company s reported cash flows or liquidity. Generally, accounting rules do not involve a selection among alternatives, but involve a selection of the appropriate policies for applying the basic principles. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to the Company.

The more significant reporting areas impacted by management s judgments and estimates are crude oil and natural gas reserve estimation, impairment of assets, oil and natural gas sales revenue accruals and provision for income tax. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, consultants and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known. The oil and natural gas sales revenue accrual is particularly subject to estimates due to the Company s status as a non-operator on all of its properties. Production information obtained from well operators is substantially delayed. This causes the estimation of recent production, used in the oil and natural gas revenue accrual, to be subject to some variations.

Oil and Natural Gas Reserves

Management considers the estimation of crude oil and natural gas reserves to be the most significant of its judgments and estimates. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. Changes in crude oil and natural gas reserve estimates affect the Company s calculation of depreciation, depletion and amortization, provision for abandonment and assessment of the need for asset impairments. On an annual basis, with a semi-annual update, the Company s consulting engineer (Pinnacle Energy Services, LLC), with assistance from Company geologists, 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. However, when significant oil and natural gas price changes occur between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing a price deck current with the period. Both DD&A and impairment were calculated in the 2009 quarter based on these updated reserve calculations. As required by the guidelines and definitions established by the SEC, these estimates are based on current crude oil and natural gas pricing held flat over the life of the properties. However, projected future crude oil and natural gas pricing assumptions are used by management to prepare estimates of crude oil and natural gas reserves used in formulating management s overall operating decisions. Based on the Company s fiscal 2008 DD&A, a 10% change in the DD&A rate per mcfe would result in a corresponding $1,978,466 annual change in DD&A expense. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

Successful Efforts Method of Accounting

The Company has elected to utilize the successful efforts method of accounting for its oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized by property using the unit-of-production method as oil and natural gas is produced. The Company s exploratory wells are all on-shore and primarily located in the mid-continent area. Generally, expenditures on exploratory wells comprise less than 10% of the Company s total expenditures for oil and natural gas properties. This accounting method may yield significantly different operating results than the full cost method.

Impairment of Assets

All long-lived assets, principally oil and natural gas properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than its estimated future net cash flows. The evaluations involve significant judgment since the results are based on estimated future events, such as inflation rates, future sales prices for oil 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 Company estimates future net cash flows on its oil and natural gas properties utilizing differentially adjusted forward pricing curves for both oil and natural gas and a discount rate in line with the discount rate used by the Company s bank to evaluate its properties. 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. A further reduction in oil and natural gas prices or a decline in reserve volumes (which are re-evaluated semi-annually) would likely lead to additional impairment that may be material to the Company. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded.

Oil and Natural Gas Sales Revenue Accrual

The Company does not operate any of its oil and natural gas properties. Drilling in the last two years has resulted in adding numerous wells with significantly larger interests, thus increasing the Company s production and revenue. On many of these wells the most current available production data is gathered from the appropriate operators and oil and natural gas index prices local to each well are used to more accurately estimate the accrual of revenue on these wells. Timely obtaining production data on all other wells from the operators is not feasible; therefore, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The oil and natural gas sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil and natural gas. These variables could lead to an over or under accrual of oil and natural gas sales at the end of any particular quarter. Based on past history, the Company s estimated accrual has been materially accurate.

Income Taxes

The estimation of the amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations as well as the completion of complex calculations, including the determination of the Company s percentage depletion deduction, if any. The excess percentage depletion calculation during interim periods represents a high-level estimate as the actual well-by-well calculation required cannot be performed until the end of the fiscal year. The Company has certain state net operating loss carryforwards (NOLs) that are recognized as tax assets when assessed as more likely than not to be utilized before their expiration dates. Criteria such as expiration dates, future excess state depletion and reversing taxable temporary differences are evaluated to determine whether the NOLs are more likely than not to be utilized before they expire. If any NOLs are determined to no longer be more likely than not to be utilized, then a valuation allowance is recognized to reduce the tax benefit of such NOLs. Although the Company s management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax matters.

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

ITEM 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 2008 production, a $.10 per mcf change in the price received for natural gas production would result in a corresponding $693,000 annual change in revenue. A $1.00 per barrel change in the price received for oil production would result in a corresponding $132,000 annual change in revenue. Cash flows could be impacted, to a lesser extent, by changes in the market interest rates related to the revolving credit facility which, as of March 31, 2009, bore interest at an annual variable interest rate equal to 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%. At March 31, 2009, the Company had $15,810,247 outstanding under this facility. Based on total debt outstanding at March 31, 2009 a .5% change in interest rates would result in a $79,000 annual change in pre-tax operating cash flow.

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 economic hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in prices.

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.

(16)

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 5, 2009.

(b) Two 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
E. Chris Kauffman	6,237,384	95,979
H. Grant Swartzwelder	6,245,061	88,302

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 (1/26/09), item 5.02	Appointment of Certain Officers
		Dated (3/10/09), 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.

May 7, 2009	/s/ Michael C. Coffman
Date	Michael C. Coffman, President and Chief Executive Officer
May 7, 2009	/s/ Lonnie J. Lowry
Date	Lonnie J. Lowry, Vice President and Chief Financial Officer
May 7, 2009	/s/ Robb P. Winfield
Date	Robb P. Winfield, Controller and Chief Accounting Officer

(17)