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

FORM 10-K

Annual Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended September 30, 2010

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

Registrant's telephone number: (405) 948-1560

Securities registered under Section 12(b) of the Act:

CLASS A COMMON STOCK (VOTING)	NEW YORK STOCK EXCHANGE
(Title of Class)	(Name of each exchange on which registered)

Securities registered under Section 12(g) of the Act:
(Title of Class)

CLASS B COMMON STOCK (NON-VOTING) $1.00 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. __ Yes X No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. __ Yes X No

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.
X Yes __No

(Facing Sheet Continued)

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files.

__ Yes __No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. __

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

Large accelerated filer___ Accelerated filer_X_ Non-accelerated filer___ Smaller reporting company ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

__ Yes _X_ No

The aggregate market value of the voting stock held by non-affiliates of the registrant, computed by using the closing price of registrant's common stock, at March 31, 2010, was $168,087,326. As of December 1, 2010, 8,310,942 shares of Class A Common stock were outstanding.

Documents Incorporated By Reference

The information required by Part III of this Report, to the extent not set forth herein, is incorporated by reference from the registrant's Definitive Proxy Statement relating to the annual meeting of stockholders to be held on March 3, 2011, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Report relates.

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The following defined terms are used in this report:
"**Bbl**" means barrel;
"**Bcf**" means billion cubic feet;
"Board" means board of directors;
"CEGT" means Centerpoint Energy Gas Transmission's East pipeline in Oklahoma;
"CEO" means Chief Executive Officer;
"CFO" means Chief Financial Officer;
"CO2" means carbon dioxide;
"COO" means Chief Operating Officer;
"DD&A" means depreciation, depletion and amortization;
"ESOP" refers to the Panhandle Oil and Gas Inc. Employee Stock Ownership and 401(k) Plan, a tax qualified, defined contribution plan;
"FASB" means the Financial Accounting Standards Board;
"gross wells" or **"gross acres"** are the wells or acres in which the Company has a working interest;
"Independent Consulting Petroleum Engineer(s)" or **"Independent Consulting Petroleum Engineering Firm(s)"** refers to DeGolyer and MacNaughton of Dallas, Texas, for proved reserves calculated as of September 30, 2010, or to Pinnacle Energy Services, L.L.C. of Oklahoma City, Oklahoma, for proved reserves calculated as of September 30, 2008 and 2009;
"LOE" means lease operating expense;
"**Mcf**" means thousand cubic feet;
"**Mcfd**" means thousand cubic feet per day;
"**Mcfe**" means natural gas stated on an Mcf basis and crude oil converted to a thousand cubic feet of natural gas equivalent by using the ratio of one Bbl of crude oil to six Mcf of natural gas;
"**minerals**", "**mineral acres**" or "**mineral interests**" refers to fee mineral acreage owned in perpetuity by the Company;
"net wells" or **"net acres"** are determined by multiplying gross wells or acres by the Company's net revenue interest in such wells or acres;
"NYMEX" refers to the New York Mercantile Exchange;
"PEPL" means Panhandle Eastern Pipeline Company's Texas/Oklahoma mainline;
"play" is a term applied to identified areas with potential oil and/or natural gas reserves;
"**PV-10**" means estimated pretax present value of future net revenues discounted at 10% using SEC rules;
"**royalty interest**" refers to well interests in which the Company does not pay a share of the costs to drill, complete and operate a well, but receives a much smaller proportionate share (as compared to a working interest) of production;
"**SEC**" means the United States Securities and Exchange Commission;
"**working interest**" refers to well interests in which the Company pays a share of the costs to drill, complete and operate a well and receives a proportionate share of production.

Fiscal year references
All references to years in this report, unless otherwise noted, refer to the Company's fiscal year end of September 30.

References to natural gas
All references to natural gas reserves, sales and prices include associated natural gas liquids.

PART I

ITEM 1 BUSINESS

GENERAL

Panhandle Oil and Gas Inc. ("Company" or "Panhandle") was founded in Range, Texas County, Oklahoma, in 1926, as Panhandle Cooperative Royalty Company and operated as a cooperative until 1979, when the Company merged into Panhandle Royalty Company and its shares became publicly traded. On April 2, 2007 the Company's name was changed to Panhandle Oil and Gas Inc. The name change was made to clear up confusion as to the nature of the Company's business operations. Panhandle has never been a Royalty Trust.

While operating as a cooperative, the Company returned most of its net income to shareholders as cash dividends. Upon conversion to a public company in 1979, although still paying dividends, the Company began to retain a substantial part of its cash flow to participate with a working interest in the drilling of wells on its mineral acreage and to purchase additional mineral acreage. Several acquisitions of additional mineral acreage and small companies were made in the '80s and '90s, and the acquisition of Wood Oil Company (now a wholly owned subsidiary) was consummated in October 2001.

In January 2006 the Company last split its Class A Common Stock on a two-for-one basis. In March 2007, the Company last increased its authorized Class A Common Stock from 12 million shares to the current 24 million shares.

The Company is involved in the acquisition, management and development of oil and natural gas properties, including wells located on the Company's mineral and leasehold acreage. Panhandle's mineral and leasehold properties are located primarily in Arkansas, Kansas, Oklahoma, New Mexico and Texas, with properties also located in seven other states. The majority of the Company's oil and natural gas production is from wells located in Oklahoma.

The Company's office is located at Grand Centre, Suite 300, 5400 North Grand Blvd., Oklahoma City, OK 73112; telephone – (405) 948-1560, facsimile – (405) 948-2038. Its website is **www.panhandleoilandgas.com**.

The Company files periodic reports with the SEC on Forms 10-Q and 10-K. These Forms, the Company's annual report to shareholders and current press releases are available free of charge through its website as soon as reasonably practicable after they are filed with the SEC. Also, the Company posts copies of its various corporate governance documents on the website. From time to time, the Company posts other important disclosures to investors in the "Press Release" or "Upcoming Events" section of the website, as allowed by SEC rules.

Materials filed with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet website at www.sec.gov that contains reports, proxy and information statements, and other information regarding the Company that has been filed electronically with the SEC.

BUSINESS STRATEGY

Typically, more than 80% of Panhandle's revenues are derived from the production and sale of oil and natural gas (see Item 8 - "Financial Statements"). The Company's oil and natural gas holdings, including its mineral acreage, leasehold acreage and working and royalty interests in producing wells are mainly in Oklahoma with other significant holdings in Arkansas, Kansas, New Mexico and Texas (see Item 2 – "Description of Properties"). Exploration and development of the Company's oil and natural gas properties are conducted in association with operating oil and natural gas companies, primarily larger independent companies. The Company does not operate any of its oil and natural gas properties, but has been an active working interest participant for many years in wells drilled on the Company's mineral properties and on third-party drilling prospects. A significant percentage of the Company's recent drilling participations have been on properties in which the Company owns mineral acreage and, in many cases, already owns an interest in a producing well in the unit. Most of these wells are in unconventional plays (shale gas) located in Oklahoma and Arkansas.

PRINCIPAL PRODUCTS AND MARKETS

The Company's principal products are natural gas and, to a lesser extent, crude oil. These products are sold to various purchasers, including pipeline and marketing companies, which service the areas where the Company's producing wells are located. Since the Company does not operate any of the wells in which it owns an interest, it relies on the operating expertise of numerous companies that operate wells in the areas where the Company owns interests. This includes expertise in the drilling and completion of new wells, producing well operations and, in most cases, the marketing or purchasing of production from the wells. Natural gas sales are principally handled by the well operator and are normally contracted on a monthly basis with third party natural gas marketers and pipeline companies. Payment for natural gas sold is received by the Company either from the contracted purchasers or the well operator. Crude oil sales are generally handled by the well operator and payment for oil sold is received by the Company from the well operator or from the crude oil purchaser.

Prices of oil and natural gas are dependent on numerous factors beyond the control of the Company, including competition, weather, international events and circumstances, supply and demand, actions taken by the Organization of Petroleum Exporting Countries ("OPEC"), and economic, political and regulatory developments. Since demand for natural gas is generally highest during winter months, prices received for the Company's natural gas production are subject to seasonal variations.

Beginning in calendar 2007, the Company entered into price risk management instruments (derivatives) to reduce the Company's exposure to short-term fluctuations in the price of natural gas. The derivative contracts apply to only a portion of the Company's natural gas production and provide only partial price protection against declines in natural gas prices. These derivative contracts expose the Company to risk of financial loss and may limit the benefit of future increases in natural gas prices. A more thorough discussion of these derivative contracts is contained in Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operation".

COMPETITIVE BUSINESS CONDITIONS

The oil and natural gas industry is highly competitive, particularly in the search for new oil and natural gas reserves. There are many factors affecting Panhandle's competitive position and the market for its products which are beyond its control. Some of these factors include the quantity and price of foreign oil imports, changes in prices received for its oil and natural gas production, business and consumer demand for refined oil products and natural gas, and the effects of federal and state regulation of the exploration for, production of and sales of oil and natural gas. Changes in existing economic conditions, weather patterns and actions taken by OPEC and other oil-producing countries have a dramatic influence on the price Panhandle receives for its oil and natural gas production.

The Company does not operate any of the wells in which it has an interest; rather it relies on companies with greater resources, staff, equipment, research and experience for operation of wells both in the drilling and production phases. The Company uses its strong financial base and its mineral and leasehold acreage ownership, coupled with its own geologic and economic evaluations, to participate in drilling operations with these larger companies. This methodology allows the Company to compete effectively in drilling operations it could not undertake on its own due to financial and personnel limits and allows it to maintain low overhead costs.

SOURCES AND AVAILABILITY OF RAW MATERIALS

The existence of recoverable oil and natural gas reserves in commercial quantities is essential to the ultimate realization of value from the Company's mineral and leasehold acreage. These mineral and leasehold properties are the raw materials to its business. The production and sale of oil and natural gas from the Company's properties is essential to provide the cash flow necessary to sustain the ongoing viability of the Company. The Company reinvests a portion of its cash flow to purchase oil and natural gas leasehold acreage and, to a lesser extent, additional mineral acreage, to assure the continued availability of acreage with which to participate in exploration, drilling and development operations and, subsequently, the production and sale of oil and natural gas. This participation in exploration and production activities and purchase of additional acreage is necessary to continue to supply the Company with the raw materials with which to generate additional cash flow. Mineral and leasehold acreage purchases are made from many owners. The Company does not rely on any particular companies or persons for the purchases of additional mineral and leasehold acreage.

MAJOR CUSTOMERS

The Company's oil and natural gas production is sold, in most cases, through its well operators to many different purchasers on a well-by-well basis. During 2010, sales through three separate well operators accounted for approximately 15%, 14% and 11%, respectively, of the Company's total oil and natural gas sales. Generally, if one purchaser declines to continue purchasing the Company's oil and natural gas, several other purchasers can be located. Pricing is generally consistent from purchaser to purchaser.

PATENTS, TRADEMARKS, LICENSES, FRANCHISES AND ROYALTY AGREEMENTS

The Company does not own any patents, trademarks, licenses or franchises. Royalty agreements on producing oil and natural gas wells stemming from the Company's ownership of mineral acreage generate a portion of the Company's revenues. These royalties are tied to ownership of mineral acreage and this ownership is perpetual, unless sold by the Company. Royalties are due and payable to the Company whenever oil and/or natural gas is produced and sold from wells located on the Company's mineral acreage.

REGULATION

All of the Company's well interests and non-producing properties are located onshore in the United States. Oil and natural gas production is subject to various taxes, such as gross production taxes and, in some cases, ad valorem taxes.

The State of Oklahoma and other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other regulations relating to the exploration for and production of oil and natural gas. These states also have regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties and the regulation of spacing, plugging and abandonment of wells. As previously discussed, the Company relies on the well operators to comply with governmental regulations.

Various aspects of the Company's oil and natural gas operations are regulated by agencies of the federal government. Transportation of natural gas in interstate commerce is generally regulated by the Federal Energy Regulatory Commission ("FERC") pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 ("NGPA"). The intrastate transportation and gathering of natural gas (and operational and safety matters related thereto) may be subject to regulation by state and local governments.

FERC's jurisdiction over interstate natural gas sales was substantially modified by the NGPA under which FERC continued to regulate the maximum selling prices of certain categories of natural gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") deregulated natural gas prices for all "first sales" of natural gas. Because "first sales" include typical wellhead sales by producers, all natural gas produced from the Company's natural gas properties is sold at market prices, subject to the terms of any private contracts in effect. FERC's jurisdiction over natural gas transportation was not affected by the Decontrol Act.

Sales of natural gas are affected by intrastate and interstate natural gas transportation regulation. Beginning in 1985, FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by FERC to foster competition by transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of natural gas transporters. As a result of the various omnibus rulemaking proceedings in the late 1980s and the individual pipeline restructuring proceedings of the early to mid-1990s, interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, FERC expanded the impact of open access regulations to intrastate commerce.

More recently, FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are: (1) permitting the large-scale divestiture of interstate pipeline-owned natural gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon the pipeline's demonstration of lack of market control in the relevant service market.

As a result of these changes, sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are able to conduct business with a larger number of counter parties. These changes generally have improved the access to markets for natural gas while substantially increasing competition in the natural gas marketplace. The effect of future regulations by FERC and other regulatory agencies cannot be predicted.

Sales of oil are not regulated and are made at market prices. The price received from the sale of oil is affected by the cost of transporting it to market. Much of that transportation is through interstate common carrier pipelines. Effective January 1, 1995, FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. Over time, these regulations tend to increase the cost of transporting oil by interstate pipeline, although some annual adjustments may result in decreased rates for a given year. These regulations have generally been upheld on judicial review. Every five years, FERC will examine the relationship between the annual change in the applicable index and the actual cost changes experienced by the oil pipeline industry.

ENVIRONMENTAL MATTERS

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays; however, to date, the Company's cost of compliance has been immaterial. The Company does not believe the existence of these environmental laws, as currently written and interpreted, will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future events or changes in laws, or the interpretation of laws, governing our industry. Current discussions involving the governance of hydraulic fracturing in the future could have a material impact on the Company. Since the Company does not operate any wells in which it owns an interest, actual compliance with environmental laws is controlled by the well operators, with Panhandle being responsible for its proportionate share of the costs involved. As such, to its knowledge, the Company is not aware of any instances of non-compliance with existing regulations and that, absent an extraordinary event, any noncompliance will not have a material adverse effect on the financial condition of the Company. Although the Company is not fully insured against all environmental risks, insurance coverage is maintained at levels which are customary in the industry.

EMPLOYEES

At September 30, 2010, Panhandle employed 18 persons on a full-time basis with five of the employees serving as executive officers. The President and CEO is also a director of the Company.

RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating the Company's business and future prospects. The risk factors described below are not necessarily exhaustive, and investors are encouraged to perform their own investigation with respect to the Company and its business. Investors should also read the other information in this Form 10-K, including the financial statements and related notes.

Worldwide and in the United States, economic recession continues to have a negative effect on demand for and the price of oil and natural gas.

Continuing effects of the economic recession could lead to: (1) a decline of oil and natural gas reserves due to curtailed drilling activity; (2) risk of insolvency of well operators and oil and natural gas purchasers; (3) limited availability of certain insurance contracts; and (4) limited access to derivative instruments. A decline in reserves would lead to a decline in production and would have a negative impact on profitability and Company value.

Oil and natural gas prices are volatile. Volatility in oil and natural gas prices can adversely affect results and the price of the Company's common stock. This volatility also makes valuation of oil and natural gas producing properties difficult and can disrupt markets.

Oil and natural gas prices have historically been and will continue to be volatile. The prices for oil and natural gas are subject to wide fluctuation in response to a number of factors, including:

- worldwide economic conditions;
- economic, political and regulatory developments;

- market uncertainty;
- relatively minor changes in the supply of and demand for oil and natural gas;
- availability and capacity of necessary transportation and processing facilities;
- commodity futures trading;
- weather conditions;
- import prices;
- political conditions in major oil producing regions, especially the Middle East and West Africa;
- actions taken by OPEC; and
- competition from alternative sources of energy.

In recent years, oil and natural gas price volatility has become increasingly severe. Price volatility makes it difficult to budget and project the return on exploration and development projects and to estimate with precision the value of producing properties that are owned or acquired. In addition, volatile prices often disrupt the market for oil and natural gas properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Results of operations may fluctuate significantly as a result of, among other things, variations in oil and natural gas prices and production performance.

A substantial decline in oil and natural gas prices for an extended period of time would have a material adverse effect on the Company.

A substantial decline in oil and natural gas prices for an extended period of time would have a material adverse effect on the Company’s financial position, results of operations, access to capital and the quantities of oil and natural gas that may be economically produced. A significant decrease in price levels for an extended period would have a material negative effect in several ways, including:

- cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves or increase production;
- certain reserves may no longer be economic to produce, leading to both lower proved reserves and cash flow; and
- access to sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable.

We cannot control activities on properties we do not operate.

The Company does not operate any of the properties in which it has an interest and has very limited ability to exercise influence over operations of these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and the limited ability to influence operations and associated costs could materially and adversely affect the realization of targeted returns on capital in drilling or acquisition activities and targeted production growth rates. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond the Company’s control, including the operator’s expertise and financial resources, approval of other participants for drilling wells and utilization of appropriate technology.

The Company’s derivative activities may reduce the cash flow received for oil and natural gas sales.

In order to manage exposure to price volatility in our natural gas, we enter into natural gas derivative contracts for a portion of our expected production. Commodity price derivatives may limit the cash flow we actually realize and therefore reduce revenues in the future. The fair value of our natural gas derivative instruments outstanding as of September 30, 2010 was an asset of $1,620,326.

Lower oil and natural gas prices may cause impairment charges.

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 development dry holes are capitalized and amortized by property using the unit-of-production method as oil and natural gas is produced.

All long-lived assets, principally the Company's 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 future net cash flows. 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. Once assets are classified as held for sale, they are reviewed for impairment. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded. If an impairment charge is recognized, cash flow from operating activities is not impacted but net income and, consequently, shareholders' equity, are reduced.

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

It is not possible to measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, future production levels, and operating and development costs. In estimating our level of oil and natural gas reserves, we and our Independent Consulting Petroleum Engineering Firm make certain assumptions that may prove to be incorrect, including assumptions relating to the level of oil and natural gas prices, future production levels, capital expenditures, operating and development costs, the effects of regulation and availability of funds. If these assumptions prove to be incorrect, our estimates of reserves (the economically recoverable quantities of oil and natural gas attributable to any particular group of properties), the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly.

Our standardized measure is calculated using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month oil and natural gas price for each month within the 12-month period prior to September 30, 2010, held flat over the life of the properties and costs in effect as of the date of estimation, less future development, production and income tax expenses, and is discounted at ten percent per annum to reflect the timing of future net revenue in accordance with the rules and regulations of the SEC. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures. Further, our lack of knowledge of all individual well information known to the well operators such as incomplete well stimulation efforts, restricted production rates for various reasons and up to date well production data, etc. may cause differences in our reserve estimates.

Because forward-looking prices and costs are not used to estimate discounted future net cash flows from our estimated proved reserves, the standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the ten percent discount factor we use when calculating discounted future net cash flows in compliance with the Financial Accounting Standards Board's ("FASB") statement on oil and natural gas producing activities disclosures may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company, or the oil and natural gas industry in general.

Failure to find or acquire additional reserves will cause reserves and production to decline materially from their current levels.

The rate of production from oil and natural gas properties generally declines as reserves are depleted. The Company's proved reserves will decline materially as reserves are produced except to the extent that the Company acquires additional properties containing proved reserves, conducts additional successful exploration and development drilling, successfully applies new technologies or identifies additional behind-pipe zones or secondary recovery reserves. Future oil and natural gas production is therefore highly dependent upon the level of success in acquiring or finding additional reserves. The above activities are conducted with well operators, as the Company does not operate any of its wells.

Drilling for oil and natural gas invariably involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. In addition, wells that are profitable may not achieve a targeted rate of return. The Company relies on the operators' seismic data and other advanced technologies in identifying prospects and in conducting exploration and development activities. The seismic data and other technologies used do not allow operators to know conclusively prior to drilling a well whether oil or natural gas is present and may be commercially produced.

Cost factors can adversely affect the economics of any project, and ultimately the cost of drilling, completing and operating a well is controlled by well operators and existing market conditions. Further drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including unexpected drilling conditions, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, environmental and other governmental requirements, the cost and availability of drilling rigs, equipment and services and potentially the expected sales price to be received for oil or natural gas produced from the wells.

Reserve estimates for September 30, 2010, calculated under the new SEC reporting rules, *Modernization of Oil and Gas Reporting Requirements*, are not directly comparable to reserve estimates made in prior years.

This report presents reserve estimates prepared using the new SEC reporting rules, *Modernization of Oil and Gas Reporting Requirements*, which are different in a number of respects from rules used for reserve estimates made in prior years. The changes include: (1) permitting use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; (2) enabling companies to additionally disclose their probable and possible reserves to investors, in addition to their proved reserves; (3) allowing previously excluded resources, such as oil sands, to be classified as oil and natural gas reserves rather than mining reserves; (4) requiring companies to report the independence and qualifications of a preparer or auditor, based on current Society of Petroleum Engineers criteria; (5) requiring the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and (6) requiring companies to report oil and natural gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The result is reserve estimates beginning with the fiscal year ended September 30, 2010 will not be directly comparable to estimated reserves reported in previous fiscal years.

Oil and natural gas drilling and producing operations involve various risks.

The Company is subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including well blowouts, cratering and explosions, pipe failures, fires, abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

The Company maintains insurance against many potential losses or liabilities arising from well operations in accordance with customary industry practices and in amounts believed by management to be prudent. However, this insurance does not protect it against all operational risks. For example, the Company does not maintain business interruption insurance. Additionally, pollution and environmental risks generally are not fully insurable. These risks could give rise to significant uninsured costs that could have a material adverse effect upon the Company's financial results.

Future legislative or regulatory changes may result in increased costs and decreased revenues, cash flows and liquidity.

Companies which operate wells in which Panhandle owns a working interest are subject to extensive federal, state and local regulation. Panhandle, as a working interest owner, is therefore indirectly subject to the same regulations. New or changed laws and regulations such as those described below could have an adverse effect on our business.

Federal Income Taxation

Proposals to repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses, if enacted, would increase and accelerate the Company's payment of federal income taxes. As a result, these changes would decrease the Company's cash flows available for developing its oil and natural gas properties.

Hydraulic Fracturing

The vast majority of oil and natural gas wells drilled in recent years, and future wells expected to be drilled, in which the Company owns an interest were, or are expected to be, hydraulically fractured as a part of the process of completing the wells and putting them on production. Some members of Congress have proposed legislation to either ban or further regulate the hydraulic fracturing process. We cannot predict whether any such legislation will be enacted or, if enacted, what its provisions would be. If legislation is passed to ban hydraulic fracturing, the number of wells drilled in the future may drop dramatically, and the economic performance of those drilled will be negatively affected. Legislation imposing further regulation of hydraulic fracturing may result in increased costs to drill, complete and operate wells, as well as delays in obtaining permits to drill wells.

Climate Change

The EPA has proposed regulations for the purpose of restricting greenhouse gas emissions from stationary sources. Also, the U.S. Congress has considered legislation that would establish a cap-and-trade program in order to reduce emissions of greenhouse gases such as carbon dioxide and methane. Such regulatory and legislative proposals to restrict greenhouse gas emissions, or to generally address climate change, could increase the Company's operating costs as operators of wells, in which the Company owns a working interest, incur costs to comply with new rules. The increase in costs to the well operators, and ultimately the Company, as a working interest owner, could include new or increased costs to install new emissions control equipment, operate and maintain existing equipment, obtain allowances to authorize greenhouse gas emissions and pay greenhouse gas related taxes. There also could be an adverse effect on demand for oil and natural gas in the market place.

Shortages of oil field equipment, services, qualified personnel and resulting cost increases could adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. There have also been shortages of drilling rigs, hydraulic fracturing equipment and personnel and other oilfield equipment, as demand for rigs and equipment increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. These shortages or price increases could adversely affect the Company's profit margin, cash flow and operating results, or restrict its ability to drill wells and conduct ordinary operations.

Competition in the oil and natural gas industry is intense, and most of our competitors have greater financial and other resources than we do.

We compete in the highly competitive areas of oil and natural gas acquisition, development, exploration and production. We face intense competition from both major and independent oil and natural gas companies in seeking to acquire desirable producing properties, seeking new properties for future exploration and seeking the human resource expertise necessary to effectively develop properties. We also face similar competition in obtaining sufficient capital to maintain drilling rights in all drilling units.

Many of our competitors have financial and other resources substantially greater than ours, and some of them are fully integrated oil and natural gas companies. These companies are able to pay more for development prospects and productive oil and natural gas properties and are able to define, evaluate, bid for, purchase and subsequently drill a greater number of properties and prospects than our financial or human resources permit, effectively reducing our right to participate in drilling on certain of our acreage as a working interest owner. Our ability to develop and exploit our oil and natural gas properties and to acquire additional quality properties in the future will depend upon our ability to successfully evaluate, select and acquire suitable properties and join in drilling with reputable operators in this highly competitive environment.

ITEM 1B UNRESOLVED STAFF COMMENTS

None

ITEM 2 PROPERTIES

At September 30, 2010, Panhandle's principal properties consisted of perpetual ownership of 254,422 net mineral acres, held principally in Arkansas, New Mexico, North Dakota, Oklahoma, Texas and six other states. The Company also held leases on 19,066 net acres primarily in Oklahoma. At September 30, 2010, Panhandle held working interests, royalty interest or both in 4,989 producing oil and natural gas wells and 40 wells in the process of being drilled or completed.

Consistent with industry practice, the Company does not have current abstracts or title opinions on all of its mineral properties and, therefore, cannot be certain that it has unencumbered title to all of these properties. In recent years, a few insignificant challenges have been made against the Company's fee title to its properties.

The Company pays ad valorem taxes on minerals owned in nine states.

ACREAGE

Mineral Interests Owned

The following table of mineral interests owned reflects, in each respective state, the number of net and gross acres, net and gross producing acres, net and gross acres leased, and net and gross acres open (unleased) as of September 30, 2010.

State	Net Acres	Gross Acres	Net Acres Producing (1)	Gross Acres Producing (1)	Net Acres Leased to Others (2)	Gross Acres Leased to Others (2)	Net Acres Open (3)	Gross Acres Open (3)
Arkansas	9,951	45,277	4,106	16,174	3,312	13,102	2,533	16,001
Colorado	8,217	39,080			223	447	7,994	38,633
Florida	5,589	12,239					5,589	12,239
Kansas	3,082	11,816	144	1,200			2,938	10,616
Montana	1,007	17,947					1,007	17,947
North Dakota	11,179	64,286	110	800			11,069	63,486
New Mexico	57,396	174,460	1,352	7,125	525	760	55,519	166,575
Oklahoma	112,975	945,038	36,799	296,339	1,099	9,029	75,077	639,670
South Dakota	1,825	9,300					1,825	9,300
Texas	43,174	359,864	7,451	70,500	547	5,578	35,176	283,786
OTHER	27	262					27	262
Total:	**254,422**	**1,679,569**	**49,962**	**392,138**	**5,706**	**28,916**	**198,754**	**1,258,515**

(1) "Producing" represents the mineral acres in which Panhandle owns a royalty or working interest in a producing well.
(2) "Leased" represents the mineral acres owned by Panhandle that are leased to third parties but not producing.
(3) "Open" represents mineral acres owned by Panhandle that are not leased or in production.

Leases

The following table reflects net mineral acres leased from others, lease expiration dates, and net leased acres held by production.

State	Net Acres	Net Lease Acres Expiring					Net Acres Held by Production
		2011	2012	2013	2014	2015	
Kansas	2,117						2,117
Oklahoma	15,077	1,597	167	600	653	32	12,028
Texas	504		3				501
Other	1,368						1,368
TOTAL	19,066	1,597	170	600	653	32	16,014

PROVED RESERVES

The following table summarizes estimates of proved reserves of oil and natural gas held by

Panhandle. All proved reserves are located within the United States and are principally made up of small interests in 4,989 wells. Other than this report, the Company's reserve estimates are not filed with any other federal agency.

Net Proved Developed Reserves	Barrels of Oil	Mcf of Natural Gas	Mcfe
September 30, 2010	861,240	57,344,190	62,511,630
September 30, 2009	882,987	45,036,460	50,334,382
September 30, 2008	895,430	35,970,450	41,343,030
Net Proved Undeveloped Reserves			
September 30, 2010	63,769	40,826,265	41,208,879
September 30, 2009	37,886	8,991,350	9,218,666
September 30, 2008	94,530	12,180,220	12,747,400
Net Total Proved Reserves			
September 30, 2010	925,009	98,170,455	103,720,509
September 30, 2009	920,873	54,027,810	59,553,048
September 30, 2008	989,960	48,150,670	54,090,430

Reserves for 2008 exclude approximately 2.9 Bcf of CO_2 gas reserves. These reserves were sold in the fourth quarter of 2009.

The determination of reserve estimates is a function of testing and evaluating the production and development of oil and natural gas reservoirs in order to establish a production decline curve. The established production decline curves, in conjunction with estimated future oil and natural gas prices, development costs, production taxes and operating expenses, are used to estimate oil and natural gas reserve quantities and associated future net cash flows. As information is processed, over time, regarding the development of individual reservoirs and as market conditions change, estimated reserve quantities and future net cash flows will change as well. Estimated reserve quantities and future net cash flows are affected by changes in product prices, and these prices have varied substantially in recent years and are expected to vary substantially from current pricing in the future.

In January 2010, the FASB updated its oil and natural gas estimation and disclosure requirements to align its requirements with the SEC's modernized oil and natural gas reporting rules, which are effective for annual reports on Form 10−K for fiscal years ending on or after December 31, 2009. The update includes the following changes: (1) permitting use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; (2) enabling companies to additionally disclose their probable and possible reserves to investors, in addition to their proved reserves; (3) allowing previously excluded resources, such as oil sands, to be classified as oil and natural gas reserves rather than mining reserves; (4) requiring companies to report the independence and qualifications of a preparer or auditor, based on current Society of Petroleum Engineers criteria; (5) requiring the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and (6) requiring companies to report oil and natural gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The update must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. Effective September 30, 2010, the Company adopted the new requirements. See Note 10 for disclosures regarding our natural gas and oil reserves.

The Company is not able to disclose the effects resulting from the implementation of these changes on the financial statements or on the amount of proved reserves and disclosed quantities. In order to accurately report the quantitative effect of applying oil and gas modernization rules, it would have been necessary for the Company to prepare two sets of reserve reports, one applying the new oil and gas modernization rules and another applying the rules in effect at September 30, 2009. The Company has interests in several thousand developed and undeveloped properties which are evaluated in the reserve estimation process. The Company has a total of eighteen employees including one petroleum engineer and one engineering tech. Staff time was not available for the engineering staff to perform necessary controls to ensure the accuracy of the report, for accounting personnel to recalculate DD&A and re-test for impairment of producing properties and be able to timely prepare and file this Form 10-K with the SEC. Therefore, the Company determined that it was not practicable to perform a second reserve estimation process under the prior rules.

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

Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas calculated the Company's oil and natural gas reserves as of September 30, 2010 (see Exhibits 23 and 99). Reserves as of September 30, 2008 and 2009 were calculated by Pinnacle Energy Services, L.L.C. of Oklahoma City, Oklahoma.

The Company's net proved (including certain undeveloped reserves described above) oil and natural gas reserves, all of which are located in the United States, as of September 30, 2010, 2009 and 2008, have been estimated by the Company's Independent Consulting Petroleum Engineering Firms. All studies have been prepared in accordance with regulations prescribed by the Securities and Exchange Commission. The reserve estimates were based on economic and operating conditions existing at September 30, 2010, 2009 and 2008. Since the determination and valuation of proved reserves is a function of testing and estimation, the reserves presented should be expected to change as future information becomes available.

ESTIMATED FUTURE NET CASH FLOWS

Set forth below are estimated future net cash flows with respect to Panhandle's net proved reserves (based on the estimated units set forth in the immediately preceding table) for the year indicated, and the present value of such estimated future net cash flows, computed by applying a 10% discount factor as required by the rules and regulations of the SEC. Estimated future net cash flows as of September 30, 2008 and 2009 have been computed by applying prices of oil and natural gas on September 30 of each year to future production of proved reserves less estimated future expenditures to be incurred with respect to the development and production of these reserves. As of September 30, 2010, the Company adopted the new SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. In accordance with the new SEC rule, the estimated future net cash flows as of September 30, 2010 were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month oil and natural gas price for each month within the 12-month period prior to September 30, 2010, held flat over the life of the properties and applied to future production of proved reserves less estimated future development and production expenditures for these reserves. The pricing used for each of the three years presented is in accordance with SEC regulations in effect for each year. The amounts presented are net of operating costs and production taxes levied by the respective states. Prices used for determining future cash flows from oil and natural gas as of September 30, 2010, 2009 and 2008, were as follows: 2010 - $69.23/Bbl, $4.33/Mcf ; 2009 - $66.96/Bbl, $2.86/Mcf; 2008 - $97.74/Bbl, $4.51/Mcf (these natural gas prices are representative of local pipelines in Oklahoma). These future net cash flows based on SEC pricing rules should not be construed as the fair market value of the Company's reserves. A market value determination would need to include many additional factors, including anticipated oil and natural gas price and production cost increases or decreases, which could affect the economic life of the properties.

Estimated Future Net Cash Flows

	9-30-10	9-30-09	9-30-08
Proved Developed	$ 202,056,455	$ 131,674,245	$ 182,996,389
Proved Undeveloped	84,200,597	15,372,040	31,863,340
Income Tax Expense	99,118,090	43,832,666	67,278,008
Total Proved	$ 187,138,962	$ 103,213,619	$ 147,581,721

10% Discounted Present Value of Estimated Future Net Cash Flows

	9-30-10	9-30-09	9-30-08
Proved Developed	$ 103,270,565	$ 73,869,512	$ 104,840,854
Proved Undeveloped	21,960,347	6,800,080	15,068,040
Income Tax Expense	52,730,503	26,923,084	41,896,610
Total Proved	$ 72,500,409	$ 53,746,508	$ 78,012,284

The future net cash flows for 9-30-08 are net of immaterial amounts of future cash flow to be received from CO2 reserves. These reserves were sold in the fourth quarter of 2009.

OIL AND NATURAL GAS PRODUCTION

The following table sets forth the Company's net production of oil and natural gas for the fiscal periods indicated.

	Year Ended 9-30-10	Year Ended 9-30-09	Year Ended 9-30-08
Bbls - Oil	102,379	128,160	132,402
Mcf - Natural Gas	8,302,342	9,109,988	6,928,038
Mcfe	8,916,616	9,878,948	7,722,450

Natural gas production includes 236,308 and 193,408 Mcf of CO2 sold at average prices of $.85 and $.86 per Mcf for the years ended September 30, 2009 and 2008, respectively.

AVERAGE SALES PRICES AND PRODUCTION COSTS

The following table sets forth unit price and cost data for the fiscal periods indicated.

Average Sales Price	Year Ended 9-30-10	Year Ended 9-30-09	Year Ended 9-30-08
Per Bbl, Oil	$ 72.83	$ 51.79	$ 103.91
Per Mcf, Natural Gas (1)	$ 4.41	$ 3.38	$ 7.98
Per Mcfe	$ 4.94	$ 3.79	$ 8.94

(1) Proceeds from the sale of natural gas liquids have been included in natural gas sales, and are therefore included in the price per Mcf of natural gas.

Average Production (lifting costs)	Year Ended 9-30-10	Year Ended 9-30-09	Year Ended 9-30-08
(Per Mcfe of Natural Gas)			
(1)	$ 0.92	$ 0.78	$ 0.86
(2)	0.16	0.12	0.44
	$ 1.08	$ 0.90	$ 1.30

(1) Includes actual well operating costs, compression, handling and marketing fees paid on natural gas sales and other minor expenses associated with well operations.

(2) Includes production taxes only. The low production tax rate per Mcfe in 2009 and 2010 is because of a large proportion of the Company's natural gas revenue coming from horizontally drilled wells which are eligible for either Oklahoma production tax credits or reduced Arkansas production tax rates.

Approximately 28% of the Company's oil and natural gas revenue is generated from royalty interests in approximately 3,600 wells. Royalty interests bear no share of the operating costs on those producing wells.

GROSS AND NET PRODUCTIVE WELLS AND DEVELOPED ACRES

The following table sets forth Panhandle's gross and net productive oil and natural gas wells as of September 30, 2010. Panhandle owns either working interests, royalty interests or both in these wells. The Company does not operate any wells.

	Gross Wells	Net Wells
Oil	997	20.47
Natural Gas	3,992	92.30
Total	4,989	112.77

Information on multiple completions is not available from Panhandle's records, but the number is not believed to be significant.

As of September 30, 2010, Panhandle owned 392,138 gross developed mineral acres and 49,962 net developed mineral acres. Panhandle has also leased from others 138,112 gross developed acres containing 16,014 net developed acres.

UNDEVELOPED ACREAGE

As of September 30, 2010, Panhandle owned 1,287,431 gross and 204,460 net undeveloped mineral acres, and leases on 28,044 gross and 3,052 net acres.

DRILLING ACTIVITY

The following net productive development and exploratory wells and net dry development and exploratory wells in which the Company had either a working interest, a royalty interest or both were drilled and completed during the fiscal years indicated. The Company did not purchase any wells during these periods.

Development Wells	Net Productive Wells	Net Dry Wells
Fiscal years ended:		
September 30, 2010	4.029693	0.057282
September 30, 2009	8.893170	0.092978
September 30, 2008	8.120236	0.067177
Exploratory Wells		
Fiscal years ended:		
September 30, 2010	0.160270	0.000000
September 30, 2009	0.867702	0.138051
September 30, 2008	0.985659	0.083333
Purchased Wells		
Fiscal years ended:		
September 30, 2010	-- 0 --	-- 0 --
September 30, 2009	-- 0 --	-- 0 --
September 30, 2008	-- 0 --	-- 0 --

PRESENT ACTIVITIES

The following table sets forth the gross and net oil and natural gas wells drilling or testing as of September 30, 2010, in which Panhandle owns either a working interest, a royalty interest or both. These wells were not yet producing at September 30, 2010.

	Gross Wells	Net Wells
Oil	7	0.15976
Natural Gas	33	0.74449

OTHER FACILITIES

The Company leases 12,369 square feet of office space in Oklahoma City, OK. The lease obligation ends in 2012.

SAFE HARBOR STATEMENT

This report, including information included in, or incorporated by reference from, future filings by the Company with the SEC, as well as information contained in written material, press releases and oral statements, contains, or may contain, certain statements that are “forward-looking statements,” within the meaning of the federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which are expected to, or anticipated will, or may, occur in the future, are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts” and similar expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, such things as: the amount and nature of our future capital expenditures; wells to be drilled or reworked; prices for oil and natural gas; demand for oil and natural gas; estimates of proved oil and natural gas reserves; development and infill drilling potential; drilling prospects; business strategy; production of oil and natural gas reserves; and expansion and growth of our business and operations.

These statements are based on certain assumptions and analyses made by the Company in light of experience and perception of historical trends, current conditions and expected future developments as well as other factors believed appropriate in the circumstances. However, whether actual results and development will conform to our expectations and predictions is subject to a number of risks and uncertainties, which could cause actual results to differ materially from our expectations.

One should not place undue reliance on any of these forward-looking statements. The Company does not currently intend to update forward-looking information and to release publicly the results of any future revisions made to forward-looking statements to reflect events or circumstances, which reflect the occurrence of unanticipated events, after the date of this report.

In order to provide a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made, the following discussion outlines certain factors that in the future could cause consolidated results for 2011 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of the Company.

Commodity Prices. The prices received for oil and natural gas production have a direct impact on the Company’s revenues, profitability and cash flows as well as the ability to meet its projected financial and operational goals. The prices for natural gas and crude oil are dependent on a number of factors beyond the Company’s control, including: the demand for oil and natural gas, weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas) and the ability of current distribution systems in the United States to effectively meet the demand for oil and natural gas at any given time, particularly in times of peak demand which may result because of adverse weather conditions.

Oil prices are sensitive to foreign influences based on political, social or economic factors, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of both natural gas and oil are becoming more and more influenced by trading on the commodities markets, which has, at times, increased the volatility associated with these prices.

Uncertainty of Oil and Natural Gas Reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond the Company’s control. The oil and natural gas reserve data included in this report represents only an estimate of these reserves. Oil and natural gas reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, development costs, and workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas and estimates of the future net cash flows from oil and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues and expenditures with respect to oil and natural gas reserves will vary from estimates, and those variances can be material.

The Company does not operate any of the properties in which it has an interest and has very limited ability to exercise influence over operations for these properties or their associated costs. Dependence on the operator and other working interest owners for these projects and the limited ability to influence operations and associated costs could materially and adversely affect the realization of targeted returns on capital in drilling or acquisition activities and targeted production growth rates.

The information regarding discounted future net cash flows included in this report is not necessarily the current market value of the estimated oil and natural gas reserves attributable to the Company's properties. As required by the SEC, the 2010 estimated discounted future net cash flows from proved oil and natural gas reserves are determined based on the fiscal year's 12-month average of the first-day-of-the-month oil and natural gas prices (oil and natural gas prices used for 2008 and 2009 were based on the September 30 spot price of each respective year) and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected, in part, by the amount and timing of oil and natural gas production, supply and demand for oil and natural gas and increases or decreases in consumption.

In addition, the 10% discount factor used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the risks associated with operations of the oil and natural gas industry in general.

ITEM 3 LEGAL PROCEEDINGS

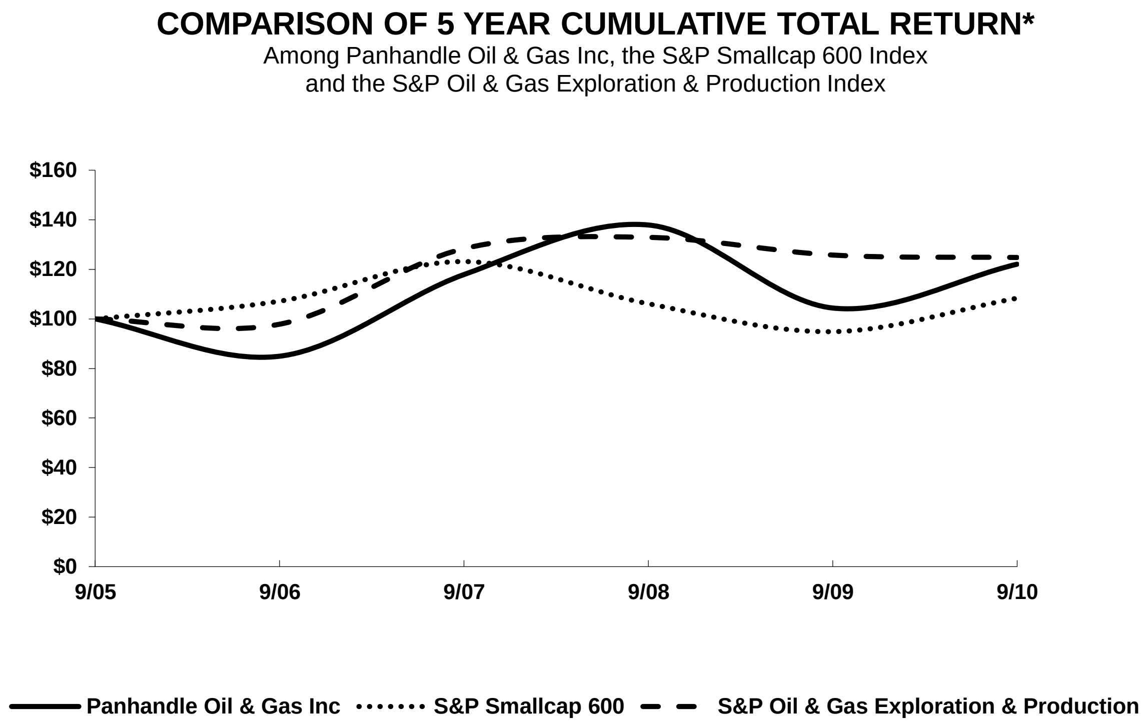
There were no material legal proceedings involving Panhandle or Wood Oil on September 30, 2010, or at the date of this report.

ITEM 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of Panhandle's security holders during the fourth quarter of the fiscal year ended September 30, 2010.

PART II

ITEM 5 MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS



*$100 invested on 9/30/05 in stock or index, including reinvestment of dividends.
Fiscal year ending September 30.

The above graph compares the cumulative 5-year total return provided shareholders on Panhandle Oil and Gas Inc.'s common stock relative to the cumulative total returns of the S&P Smallcap 600 index and the S&P Oil & Gas Exploration & Production index. An investment of $100 (with reinvestment of all dividends) is assumed to have been made in our common stock and in each of the indexes on September 30, 2005, and its relative performance is tracked through September 30, 2010.

On July 22, 2008, the Company's Class A Common Stock ("Common Stock") was listed on the New York Stock Exchange (symbol PHX) and, prior to that, it was listed on the American Stock Exchange under the same symbol. The following table sets forth the high and low trade prices of the Common Stock during the periods indicated:

Quarter Ended	High	Low
December 31, 2008	$ 28.18	$ 13.75
March 31, 2009	$ 23.75	$ 13.15
June 30, 2009	$ 24.62	$ 15.79
September 30, 2009	$ 28.02	$ 18.17
December 31, 2009	$ 26.25	$ 19.06
March 31, 2010	$ 29.65	$ 20.34
June 30, 2010	$ 29.29	$ 21.97
September 30, 2010	$ 30.31	$ 21.00

As of November 22, 2010, there were 1,716 holders of record of Panhandle's Class A Common Stock and approximately 4,000 beneficial owners.

During the past two years, cash dividends have been declared and paid as follows on the Class A Common Stock:

Date	Rate Per Share
December 2008	$0.07
March 2009	$0.07
June 2009	$0.07
September 2009	$0.07
December 2009	$0.07
March 2010	$0.07
June 2010	$0.07
September 2010	$0.07

Approval by the Company's board of directors is required before the declaration and payment of any dividends.

While the Company anticipates it will continue to pay dividends on its common stock, the payment and amount of future cash dividends will depend upon, among other things, financial condition, funds from operations, the level of capital and development expenditures, future business prospects, contractual restrictions and any other factors considered relevant by the board of directors.

The Company's credit facility also contains a provision limiting the paying or declaring of a cash dividend to fifteen percent of net cash flow provided by operating activities from the Consolidated Statement of Cash Flows of the preceding 12-month period. See Note 4 to the consolidated financial statements contained herein at Item 8 – "Financial Statements," for a further discussion of the credit facility.

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. These programs were completed in 2008. Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan on March 11, 2010, the board of directors approved repurchase of up to $1.5 million of the Company's common stock, from time to time, equal to the aggregate number of shares of common stock awarded pursuant to the Company's 2010 Restricted Stock Plan, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors. The shares are held in treasury and are accounted for using the cost method. At September 30, 2010 and September 30, 2009, 11,632 and 11,508 (respectively) treasury shares were contributed to the Company's ESOP on behalf of the ESOP participants.

ITEM 6 SELECTED FINANCIAL DATA

The following table summarizes consolidated financial data of the Company and should be read in conjunction with the "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements of the Company, including the Notes thereto, included elsewhere in this report.

	As of and for the year ended September 30,				
	2010	2009	2008	2007	2006
Revenues					
Oil and natural gas sales	$ 44,068,947	$ 37,421,688	$ 69,026,785	$ 37,449,174	$ 36,008,527
Lease bonuses and rentals	1,120,674	188,906	167,559	208,625	410,984
Gains (losses) on derivative contracts	6,343,661	(661,828)	(940,823)	765,316	-
Income from partnerships	405,134	323,848	631,891	383,391	536,365
	51,938,416	37,272,614	68,885,412	38,806,506	36,955,876
Costs and expenses					
Lease oper. exp. and prod. taxes	9,639,864	8,897,235	10,055,762	6,057,456	5,262,834
Exploration costs	1,583,773	711,582	455,943	1,050,069	222,892
Depr., depl. and amortization	19,222,123	28,168,933	19,784,660	15,291,625	10,142,367
Provision for impairment	605,615	2,464,520	526,380	3,761,832	3,009,953
Loss (gain) on asset sales, int. & other	(1,028,148)	(2,677,407)	14,826	65,568	(178,288)
Gen. and administrative	5,594,499	4,866,044	5,006,512	3,877,492	3,335,899
Bad debt expense (recovery)	-	(185,272)	591,258	-	-
	35,617,726	42,245,635	36,435,341	30,104,042	21,795,657
Income (loss) before provision (benefit) for income taxes	16,320,690	(4,973,021)	32,450,071	8,702,464	15,160,219
Provision (benefit) for income taxes	4,901,000	(2,568,000)	10,894,302	2,359,000	4,586,000
Net income (loss)	$ 11,419,690	$ (2,405,021)	$ 21,555,769	$ 6,343,464	$ 10,574,219
Basic and diluted earnings (loss) per share	$ 1.36	$ (0.29)	$ 2.54	$ 0.75	$ 1.25
Dividends declared per share	$ 0.28	$ 0.28	$ 0.28	$ 0.25	$ 0.185
Weighted average shares outstanding					
Basic and diluted	8,422,387	8,397,337	8,492,378	8,499,233	8,479,406
Net cash provided by (used in):					
Operating activities	$ 27,806,475	$ 37,710,606	$ 40,063,896	$ 28,106,500	$ 23,470,145
Investing activities	$ (9,845,516)	$ (36,322,992)	$ (37,846,172)	$ (26,940,679)	$ (21,118,606)
Financing activities	$ (13,003,609)	$ (1,643,414)	$ (2,311,376)	$ (610,814)	$ (3,556,019)
Total assets	$ 105,124,839	$ 108,549,632	$ 122,007,183	$ 78,539,797	$ 70,949,242
Long-term debt	$ -	$ 10,384,722	$ 9,704,100	$ 4,661,471	$ 1,166,649
Shareholders' equity	$ 73,581,996	$ 64,122,343	$ 68,348,901	$ 53,681,371	$ 49,065,697

All share and per-share amounts are adjusted for the effect of a 2-for-1 stock split effective in January 2006.

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

RESULTS OF OPERATIONS

General

The Company's principal line of business is to explore for, develop, produce and sell oil and natural gas. Results of operations are dependent primarily upon reserve quantities and associated exploration and development costs in finding new reserves, production quantities and related production costs and oil and natural gas sales prices. Oil and natural gas prices have rebounded somewhat since last year resulting in increased revenues. On the other hand, drilling activity on the Company's acreage remained low through the first nine months of fiscal 2010 and the Company accordingly experienced a decline in production. We have seen an increase in drilling during the last quarter of fiscal 2010 and are experiencing a shift in drilling activity toward oil and natural gas liquids-rich areas where the Company owns mineral acreage such as the Anadarko (Cana) Woodford Shale, Horizontal Granite Wash, Cleveland, Tonkawa and other areas in western Oklahoma. As of September 30, 2010, the Company had 32 working interest wells which were drilling or testing in which the Company owns an average 2.5% net revenue interest. Production from these wells, combined with other wells to be drilled in the oil and natural gas liquids-rich areas, is expected to provide an increase in production for 2011. Also, the first well in our internally generated Joiner City prospect, a horizontal Woodford Shale prospect in the oil and natural gas liquids-rich Marietta Basin in southern Oklahoma, is expected to be completed during the first quarter of 2011.

Increased oil and natural gas prices, as well as drilling success during 2010, resulted in higher oil and natural gas reserves as of September 30, 2010. The increased reserves in turn resulted in lower DD&A and impairment costs during 2010.

With the expected increase in drilling activity on our acreage during 2011, we expect additions to properties and equipment for oil and natural gas activities to significantly increase in 2011 compared to 2010. Additions to properties and equipment are distinct from capital expenditures in that these include cash and accrued additions; therefore, additions to properties and equipment represent amounts added to properties and equipment in the period, whereas capital expenditures represent amounts paid in the period. During 2010, we paid off all amounts borrowed under our credit facility and ended 2010 with a cash balance of approximately $5.6 million. The Company's debt-free position, combined with its cash holdings, provides the resources for the Company to capitalize on the current increase in drilling on its acreage.

The Company had no off balance sheet arrangements during 2010 or prior years.

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

	For the Year Ended September 30,				
	2010	Percent Incr. or (Decr.)	2009	Percent Incr. or (Decr.)	2008
Production:					
Oil (Bbls)	102,379	-20%	128,160	-3%	132,402
Natural Gas (Mcf)	8,302,342	-9%	9,109,988	31%	6,928,038
Mcfe	8,916,616	-10%	9,878,948	28%	7,722,450
Average Sales Price:					
Oil (per Bbl)	$ 72.83	41%	$ 51.79	-50%	$ 103.91
Natural Gas (Mcf) (1)	$ 4.41	30%	$ 3.38	-58%	$ 7.98
Mcfe	$ 4.94	30%	$ 3.79	-58%	$ 8.94

(1) Proceeds from the sale of natural gas liquids have been included in natural gas sales, and are therefore included in the price per Mcf of natural gas.

Fiscal Year 2010 Compared to Fiscal Year 2009

Overview

The Company recorded net income of $11,419,690, or $1.36 per share, in 2010, compared to net loss of $2,405,021, or $.29 per share, in 2009. Increased revenues in 2010 were mainly from increases in oil and natural gas sales, gains on derivative contracts and lease bonuses. Higher oil and natural gas prices more than offset a 10% decrease in production resulting in increased oil and natural gas sales; actual and forward looking prices lower than the Company's fixed price swap contracts resulted in gains on derivative contracts in 2010, compared to a loss in 2009; and the renewal of leases on most of the

Company's Arkansas undeveloped mineral acreage increased 2010 revenue from lease bonuses.

The decrease in expenses is primarily related to lower DD&A and impairment costs, resulting from the increase in oil and natural gas reserves (as of September 30, 2010) which lowered the DD&A rate per Mcfe of production. In 2010, an income tax expense of $4,901,000 was incurred compared to a tax benefit of $2,568,000 recognized in 2009.

Oil and Natural Gas (and associated natural gas liquids) Sales

Oil and natural gas sales increased $6,647,259 or 18% for 2010 as compared to 2009. Despite a 10% decrease in oil and natural gas production, 2010 oil and natural gas sales went up approximately $6.6 million (compared to 2009) driven by higher oil and natural gas prices of 41% and 30%, respectively. The production decrease occurred as fewer new wells were drilled and put on line in 2010, thus the production decline of existing wells exceeded the production which came on line from new wells.

Production by quarter for 2010 was as follows:

First quarter	2,278,133	Mcfe
Second quarter	2,090,154	Mcfe
Third quarter	2,236,236	Mcfe
Fourth quarter	2,312,093	Mcfe
Total	8,916,616	Mcfe

Drilling activity on our acreage was low through the first three quarters of 2010; however, well proposals and drilling have increased since. The new well proposals reflect a shift to oil and natural gas liquids-rich areas where the Company owns mineral acreage, such as the Anadarko (Cana) Woodford Shale, Horizontal Granite Wash, Cleveland, Tonkawa and other areas in western Oklahoma. Because of both the increase in wells being proposed and drilled on our acreage and the shift to oil and natural gas liquids-rich areas with improved well economics, we expect the Company's production to increase in 2011.

Lease Bonus and Rentals

Lease bonus and rentals increased $931,768 for 2010 as compared to 2009. This increase was mostly due to the renewal of leases on most of the Company's Arkansas undeveloped mineral acreage which increased 2010 revenue from lease bonuses approximately $723,000.

Gains (Losses) on Natural Gas Derivative Contracts

Realized and unrealized gains and losses are scheduled below:

Gains (losses) on derivative contracts	Fiscal year 2010	Fiscal year 2009
Realized	$2,209,900	$2,497,800
Unrealized	4,133,761	(3,159,628)
Total	$6,343,661	($661,828)

Lease Operating Expenses (LOE) and Production Taxes

LOE increased $497,293 or 7% in 2010. LOE costs per Mcfe of production increased from $.78

in 2009 to $.92 in 2010. Increased natural gas prices, which increased value based fees (primarily gathering, transportation and marketing costs) caused total LOE and LOE per Mcfe to increase. Natural gas production from the southeast Oklahoma Woodford Shale, Anadarko (Cana) Woodford Shale and Fayetteville Shale areas continues to increase as a proportion of total production. Value based fees are charged as a percent of natural gas revenues and are significantly higher in these shale areas than like fees charged in other of the Company's production areas. The total amount of value based fees in these three shale areas typically are 12% to 22% of total natural gas revenues. Value based fees increased $1,201,209, or 36%, in 2010 compared to 2009. Value based fees per Mcfe increased $.17, or 51%, in 2010 compared to 2009.

The increase in value based fees is partially offset by a decrease of $703,916 in LOE related to field operating costs in 2010 compared to 2009, a 16% decrease. In 2010, field operating costs were $.38 per Mcfe compared to $.42 per Mcfe in 2009, a 9% decrease. These decreases are due to fewer new wells coming on line in 2010 with high initial LOE, fewer well repairs made in 2010 compared to 2009 and the fiscal 2009 sale of wells in the Southeast Leedey field and the McElmo Dome Unit, thus reducing fiscal 2010 LOE.

Production taxes increased $245,336 or 20% in 2010. The increase is the result of increased sales of oil and natural gas. 2010 oil and natural gas sales increased 18%, and production taxes increased 20%, compared to 2009. Production taxes were 3.3% of oil and natural gas sales in 2010, compared to 3.2% in 2009. The low overall production tax rate is due to a large proportion of the Company's natural gas revenues coming from horizontally drilled wells, which are eligible for either Oklahoma production tax credits or reduced Arkansas production tax rates.

Exploration Costs

Exploration costs were $1,583,773 in 2010 compared to $711,582 in 2009, an $872,191 increase. During 2010, leasehold impairment and expired leases totaled $1,191,598 compared to $634,918 during 2009, a $556,680 increase. Five exploratory dry holes incurred expenses of approximately $77,000 during 2009; one exploratory dry hole incurred expenses of approximately $5,000 during 2010.

Also, the Company charged approximately $387,000 to exploration costs in 2010 related to geological and geophysical costs paid upon the execution of a joint exploration agreement with a privately held independent operator to explore for oil in eastern Oklahoma.

Depreciation, Depletion and Amortization (DD&A)

Total DD&A decreased $8,946,810 or 32% in 2010, while DD&A per Mcfe decreased to $2.16 in 2010 as compared to $2.85 in 2009. Approximately $2,744,000 of the DD&A decrease is the result of a 10% decrease in 2010 oil and natural gas production. The remaining DD&A decrease of approximately $6,203,000 is attributable to the $.69 decline in the DD&A rate per Mcfe. This rate declined as a result of increased proved developed oil and natural gas reserves as of September 30, 2010 (see Note 10 – Supplementary Information on Oil and Natural Gas Reserves), as compared to September 30, 2009, and a net reduction during fiscal year 2009 of approximately $3.1 million of asset basis subject to DD&A. This asset basis reduction occurred as fiscal 2009 DD&A and impairment, combined with the basis reduction associated with assets sold, exceeded new additions to properties and equipment for oil and natural gas activities.

Provision for Impairment

The provision for impairment decreased $1,858,905 in 2010 as compared to 2009. During 2010, impairment of $605,615 was recorded on seven fields. Approximately $380,000 of the impairment was related to the Buffalo Wallow field in Texas, where the first horizontal well in the field was recently drilled and completed with poor economic results. During 2009, impairment of $2,464,520 was recorded on 13 fields driven by depressed oil and natural gas prices, which negatively affected the estimates of future net revenues from oil and natural gas properties.

Loss (Gain) on Asset Sales, Interest and Other

In 2010, the Company received $1,124,682 from the settlement of a lawsuit related to one well in western Oklahoma. In 2009, the Company sold a portion of its working interest in the Southeast Leedey field and all of its working interest in the McElmo Dome CO2 Unit for a combined gain of approximately $2.5 million.

General and Administrative Costs (G&A)

G&A increased $728,455 or 15% in 2010 due to increases in the following expense categories: personnel $433,847; legal $161,016; board of directors $101,474; and insurance $87,350. Personnel expenses increased mainly because of higher accrued performance bonuses based on improved Company performance metrics in fiscal 2010 compared to 2009. Legal expense increased primarily due to legal costs of approximately $129,000 incurred during 2010 on a lawsuit related to one well in western Oklahoma. The addition of a new director, an increase in the number of Board meetings and increased director fees comprise the increase in board of directors' expense in 2010.

Bad Debt Expense (Recovery)

On July 22, 2008, SemGroup, L.P. and certain subsidiaries (SemGroup) filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy code. On October 28, 2009, the U.S. Bankruptcy Court confirmed the Fourth Amended Joint Plan of Affiliated Debtors which set forth various settlement details for producers and interest owners. Based on the details of the plan, discussion with operators impacted and management's judgment, the Company lowered the reserve for doubtful accounts to $405,129 at September 30, 2009, resulting in $186,129 of bad debt recovery. No adjustments were made in 2010 to the Company's reserve for doubtful accounts.

Provision (Benefit) for Income Taxes

The 2010 provision for income taxes of $4,901,000 was a result of a pre-tax income of $16,320,690, as compared to a benefit for income taxes of $2,568,000 in 2009, resulting from a pre-tax loss of $4,973,021. The provision for income taxes increased in 2010 by $7,469,000, the result of a $21,293,711 increase in income (loss) before provision (benefit) for income taxes in 2010, compared to 2009, partially offset by the removal of the $278,000 valuation allowance on Oklahoma NOLs. The effective tax rate for 2010 was 30%, whereas the effective tax benefit rate for 2009 was 52%. The Company's utilization of excess percentage depletion (which is a permanent tax benefit) decreased the provision for income taxes in 2010, whereas it increased the tax benefit in 2009. The effect of this permanent tax benefit is that the effective tax rate is decreased when recording a provision for income taxes as in 2010, while increasing the effective tax rate when recording a benefit for income taxes as in 2009. The benefit of excess percentage depletion is not directly related to the amount of recorded income or loss. Accordingly, in cases where the recorded income or loss is relatively small, the proportional effect of the excess percentage depletion on the effective tax rate may become significant. The reversal of the $278,000 valuation allowance on Oklahoma NOLs reduced the effective tax rate by 2% for 2010.

Liquidity and Capital Resources

At September 30, 2010, the Company had positive working capital of $10,098,861, as compared to positive working capital of $3,436,692 at September 30, 2009.

ANALYSIS OF CHANGE IN WORKING CAPITAL

	As of 9/30/2010	As of 9/30/2009	Change
CURRENT ASSETS:			
Cash and cash equivalents **(1)**	$ 5,597,258	$ 639,908	$ 4,957,350
Oil and natural gas sales receivables (net)	9,063,002	7,747,557	1,315,445
Refundable production taxes **(2)**	804,120	616,668	187,452
Derivative contracts **(3)**	1,481,527	-	1,481,527
Deferred income taxes **(4)**	-	1,934,900	(1,934,900)
Other	412,778	68,817	343,961
Total current assets	17,358,685	11,007,850	6,350,835
CURRENT LIABILITIES:			
Accounts payable	5,062,806	4,810,687	252,119
Derivative contracts **(3)**	-	1,726,901	(1,726,901)
Deferred income taxes	354,100	53,100	301,000
Accrued income taxes and other liabilities **(5)**	1,842,918	980,470	862,448
Total current liabilities	7,259,824	7,571,158	(311,334)
WORKING CAPITAL	$ 10,098,861	$ 3,436,692	$ 6,662,169

(1) During 2010, cash provided by operating activities exceeded cash used in investing activities enabling the Company to pay off its line-of-credit during May 2010.

(2) Refundable production taxes of approximately $759,000, previously reported as non-current, have now become current, thus increasing current refundable production taxes. This increase was partially offset by payments received during fiscal 2010 of approximately $518,000.

(3) The Company's current portion of fair value of derivative contracts has changed from a liability of $1,726,901 as of September 30, 2009, to an asset of $1,481,527 as of September 30, 2010, due to lower forward-looking natural gas prices as of September 30, 2010. The Company has received net payments relative to its derivative contracts of $2,209,900 during 2010.

(4) Approximately $1,039,000 of the decrease in the current assets portion of deferred income taxes relates to expected utilization of the Company's Alternative Minimum Tax (AMT) credit during fiscal 2010. The change from a liability to an asset in the unrealized value of the Company's derivative contracts (as mentioned above) decreased the current asset portion of deferred income taxes approximately $896,000.

(5) Income taxes payable increased $583,625 on higher net income before tax. Accrued liabilities for employee bonuses increased a combined $268,682.

ANALYSIS OF CHANGE IN CASH PROVIDED BY OPERATING ACTIVITIES

	12 months ended 9/30/2010	12 months ended 9/30/2009	Change
Net income (loss)	$ 11,419,690	$ (2,405,021)	$ 13,824,711
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
DD&A and impairment **(1)**	19,827,738	30,633,453	(10,805,715)
Provision for deferred income taxes **(2)**	777,000	(3,814,000)	4,591,000
Exploration costs **(3)**	1,208,653	711,582	497,071
Net (gain) loss on asset sales and other **(4)**	(1,189,605)	(2,654,759)	1,465,154
Income from partnerships	(405,134)	(323,848)	(81,286)
Distributions received from partnerships	523,317	432,805	90,512
Other	64,555	4,708	59,847
Common stock contributed to ESOP	287,194	245,811	41,383
Common stock (unissued) to Directors' Deferred Compensation Plan	359,628	256,688	102,940
Restricted stock awards	12,028	-	12,028
Bad debt expense (recovery)	-	(185,272)	185,272
Cash provided by changes in assets and liabilities:			
Oil and natural gas sales receivables **(5)**	(1,315,445)	9,620,843	(10,936,288)
Fair value of derivative contracts **(6)**	(4,133,761)	3,159,628	(7,293,389)
Refundable income taxes **(7)**	-	2,162,305	(2,162,305)
Refundable production taxes **(8)**	(69,874)	(921,769)	851,895
Other current assets	(343,961)	74,455	(418,416)
Accounts payable	(24,896)	287,883	(312,779)
Income taxes payable **(7)**	583,625	338,511	245,114
Accrued liabilities	225,723	86,603	139,120
Net cash provided by operating activities	$ 27,806,475	$ 37,710,606	$ (9,904,131)

(1) DD&A declined as a result of a decline in oil and natural gas production, increased oil and natural gas reserves and a net reduction during fiscal year 2009 in asset basis, as DD&A, impairment and basis in assets sold during 2009 exceeded additions to properties and equipment. An impairment of $605,615 was recorded in 2010, compared to $2,464,520 in 2009. For further discussion related to these items, see “Depreciation, Depletion and Amortization” and “Provision for Impairment” in Management’s Discussion and Analysis.

(2) The deferred income tax expense change of $4,591,000 resulted from a provision for deferred income taxes during 2010 of $777,000, compared to a deferred income tax benefit of $3,814,000 during 2009. Deferred income tax provisions or benefits are primarily related to expenditures for intangible drilling costs, which are expensed for tax purposes in the year incurred, but amortized over the life of the oil and natural gas properties for financial purposes, thus creating an income tax timing difference. Levels of expenditures for intangible drilling costs in relation to the before tax income or loss were significantly less in 2010 than in 2009.

(3) Leases expired or impaired during 2010 exceeded those expired or impaired during 2009 by approximately $557,000.

(4) In 2010, we received $1,124,682 from the settlement of a lawsuit related to one well in western Oklahoma. In 2009, the Company sold a portion of its working interest in the Southeast Leedey field and all of its working interest in the McElmo Dome CO2 Unit for a combined gain of approximately $2.5 million.

(5) For the year ending September 30, 2010, oil and natural gas sales receivables increased due to higher average oil and natural gas prices; whereas, through September 30, 2009, oil and natural gas sales receivables had decreased primarily as a result of lower average oil and natural gas prices. The net change to cash provided by operating activities was a decrease of $10,936,288; as receivables collected during 2009 exceeded those collected during 2010.

(6) During 2010, the Company had an unrealized gain related to derivative contracts of $4,133,761. During 2009, we had an unrealized loss related to derivative contracts of $3,159,628.

(7) During 2010, income taxes payable increased $583,625; whereas, during 2009 income taxes payable increased $338,511 resulting in a positive impact to net cash provided by operating activities of $245,114. Refundable income taxes did not change during 2010 and decreased $2,162,305 (primarily due to refund payments of approximately $2.2 million) during 2009. Refundable income taxes and income taxes payable overall had a negative effect change of $1,917,191 in 2010 compared to 2009.

(8) During 2010, we received payment of approximately $552,000 of refundable production taxes, which were reflected as a receivable at September 30, 2009.

Additions to properties and equipment for oil and natural gas activities during 2010 were $11,585,521 ($28,540,290 in 2009). Average natural gas prices during 2010 were higher than 2009; yet drilling activity on our acreage did not increase until the fourth quarter of 2010. With this increase in drilling, we are experiencing a shift in drilling activity toward oil and natural gas liquids-rich areas where the Company owns significant mineral acreage such as the Anadarko (Cana) Woodford Shale, Horizontal Granite Wash, Cleveland, Tonkawa and other plays in western Oklahoma. As of September 30, 2010, the Company had 32 working interest wells which were drilling or testing in which the Company owns an average 2.5% net revenue interest. Production from these wells combined with other wells to be drilled in the oil and natural gas liquids-rich areas during 2011 is expected to result in a production increase in 2011, compared to 2010.

Also, the first well in our internally generated Joiner City prospect, a horizontal Woodford Shale prospect in the oil and natural gas liquids-rich Marietta Basin in southern Oklahoma, is expected to be completed during the first quarter of 2011. The Company owns 2,557 acres, or approximately 6.7% of 60 sections (or drilling units), within the prospect. Due to the increase in drilling activity on our acreage, management currently projects 2011 properties and equipment additions to be approximately $27 million, compared to approximately $12 million during 2010.

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

For 2010, cash provided by operating activities was $27,806,475, well in excess of capital expenditures of $11,308,506. This excess allowed us to reduce bank debt by $10,384,722, which paid off the Company's line-of-credit during May 2010. Looking forward, the Company expects to fund capital additions, overhead costs and dividend payments primarily from cash provided by operating activities. However, during times of oil and natural gas price decreases, or increased expenditures for drilling, the Company has utilized its revolving line-of-credit facility in the past to help fund these expenditures. The Company's continued drilling activity, combined with normal delays in receiving first payments from new production, could result in future borrowings under the Company's credit facility. The Company has availability ($35 million at September 30, 2010) under its revolving credit facility and also is in 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.

Contractual Obligations and Commitments

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. The current borrowing base is $35,000,000. The revolving loan matures on October 31, 2012. Borrowings under the revolving loan are due at maturity. The revolving loan bears interest at the national prime rate plus a range of .50% to 1.25%, or 30 day LIBOR plus a range of 2.00% to 2.75% annually. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of the Company's oil and natural gas properties is advanced.

Determinations of the borrowing base are made semi-annually or whenever BOK believes there has been a material change in the value of the Company's 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 September 30, 2010, the Company was in compliance with these covenants.

The table below summarizes the Company's contractual obligations and commitments as of September 30, 2010:

Contractual Obligations and Commitments	Payments due by period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$ -	$ -	$ -	$ -	$ -
Building lease	$ 323,141	$ 204,089	$ 119,052	$ -	$ -

At September 30, 2010, the Company's derivative contracts were in a net asset position of $1,620,326. The ultimate settlement amounts of the derivative contracts are unknown because they are subject to continuing market risk. Please read Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 1 of Notes to Consolidated Financial Statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding the derivative contracts.

As of September 30, 2010, the Company's asset retirement obligations were $1,730,369. Asset retirement obligations represent the Company's share of the future expenditures to plug and abandon the wells in which the Company owns a working interest when the oil and natural gas reserves are depleted. Please read Note 1 of Notes to Consolidated Financial Statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding the Company's asset retirement obligations.

Fiscal Year 2009 Compared to Fiscal Year 2008

Overview

The Company recorded a net loss of $2,405,021, or $.29 per share, in 2009, compared to net income of $21,555,769, or $2.54 per share, in 2008. Lower oil and natural gas prices during 2009 resulted in significantly lower total revenues in 2009 as compared to 2008, notwithstanding substantially increased production volumes. Total expenses increased in 2009 over 2008 as there were significant increases in DD&A and provision for impairment, which were partially offset by decreases in lease operating expenses and production taxes, general and administrative expenses and bad debt expense. An income tax benefit of approximately $2.6 million was incurred in 2009, whereas approximately $10.9 million of income tax expense was recognized in 2008.

Oil and Natural Gas (and associated natural gas liquids) Sales

Oil and natural gas sales decreased $31,605,096 or 46% for 2009 as compared to 2008. The decrease in oil and natural gas sales was largely due to a 50% decrease in oil prices and a 58% decrease in natural gas prices, partially offset by a 28% increase in production on a Mcfe basis. Production increased even though 2009 additions to properties and equipment for oil and natural gas activities decreased significantly compared to 2008. This occurred because many wells in which the Company owned significant working interests (as high as 42%) came on line in the latter half of 2008 and in the first quarter of 2009 (resulting in nearly a full year's production being recorded in 2009). The majority of new production which came on line in 2009 was from wells in the Woodford Shale in southeast Oklahoma and the Fayetteville Shale in Arkansas.

Production by quarter for 2009 was as follows:

First quarter	2,495,299	Mcfe
Second quarter	2,380,124	Mcfe
Third quarter	2,647,474	Mcfe
Fourth quarter	2,356,051	Mcfe
Total	9,878,948	Mcfe

Gains (Losses) on Natural Gas Derivative Contracts

Realized and unrealized gains and losses are scheduled below:

Gains (losses) on derivative contracts	Fiscal year 2009	2008
Realized	$2,497,800	($1,480,100)
Unrealized	(3,159,628)	539,277
Total	($661,828)	($940,823)

Lease Operating Expenses (LOE) and Production Taxes

LOE increased $1,066,856 or 16% in 2009. LOE costs per Mcfe of production decreased from $.86 in 2008 to $.78 in 2009. As a result of continued drilling and completion of new wells, the Company's ownership of net wells increased. This increase in well ownership combined with high initial LOE on newly completed wells resulted in increased overall LOE costs. However, certain LOE costs such as transportation, compression and marketing of natural gas decreased dramatically on a per Mcfe basis due to the much lower natural gas sales prices on which these expenses were calculated (on a percentage basis). These lower expenses plus the significant increase in total Mcfe production lowered per Mcfe costs.

Production taxes decreased $2,225,383 or 65% in 2009. The decrease was primarily the result of significantly lower oil and natural gas sales in 2009, as production taxes are paid as a percentage of sales. However, the decrease was not proportional to the sales decrease due to new horizontal wells which came on line in Arkansas and Oklahoma which qualified for production tax credits or lower production tax rates from these states. These horizontally drilled wells are primarily in the Woodford Shale play in southeast Oklahoma and the Fayetteville Shale play in Arkansas.

Exploration Costs

Exploration costs were $711,582 in 2009 compared to $455,943 in 2008, a $255,639 increase. Expired, impaired or abandoned leasehold costs charged to exploration costs in 2009 were $169,564 more than in 2008. Five exploratory dry holes (in which the Company had very small working interests) were drilled in 2009 compared to none during 2008 resulting in an $86,075 increase in exploration costs related to exploratory dry holes.

Depreciation, Depletion and Amortization (DD&A)

Total DD&A increased $8,384,273 or 42% in 2009, while DD&A per Mcfe increased to $2.85 in 2009 as compared to $2.56 in 2008. The 28% increase in total Mcfe produced in 2009, as compared to the 2008 period, accounted for approximately $5.5 million of the overall DD&A increase. The remaining increase of approximately $2.9 million was attributable to the increase in DD&A per Mcfe which was related to lower oil and natural gas reserve volumes per well resulting from lower oil and natural gas prices (expected reserves per well decrease when oil and natural gas prices decline as the lower prices result in wells reaching their economic limits earlier in time, thus shortening the wells' economic lives and increasing the DD&A rate per Mcfe of production), and the substantially higher drilling and completion costs for horizontally drilled wells, primarily in the Woodford and Fayetteville Shale areas. These same wells also accounted for the majority of the 2009 increase in natural gas production.

Provision for Impairment

The provision for impairment increased $1,938,140 in 2009 as compared to 2008. In 2009, thirteen fields were impaired $2,433,652, whereas in 2008 seven fields were impaired $514,180. The amount and number of fields impaired increased in 2009 as lower oil and natural gas price projections were used to calculate oil and natural gas reserves and future net cash flows as compared to 2008. These lower price projections resulted in lower future net cash flows and lower estimated fair value, which is used to test each field for impairment.

Loss (Gains) on Asset Sales, Interest and Other

During 2009, the Company sold a portion of its interest in the Southeast Leedey Field in Oklahoma and all of its interest in the McElmo Dome Unit in Colorado, the Company's sole source of CO_2 production. The total proceeds from the 2009 sale of these interests were approximately $3.4 million; the combined gain was approximately $2.5 million, whereas approximately $16,000 was recorded as gain on sale of assets in 2008. Loss on sale of assets decreased $204,189 in 2009 as compared to 2008. Two low performing wells in western Oklahoma were sold in 2008 at a loss, while none were sold at a loss in 2009.

General and Administrative Costs (G&A)

G&A decreased $140,468 or 3% in 2009 due to decreased personnel related costs of approximately $229,000, 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 $106,000.

Bad Debt Expense (Recovery)

Bad debt expense decreased $776,530 in 2009 as compared to 2008. On July 22, 2008, SemGroup, L.P. and certain subsidiaries (SemGroup) filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy code. All of the 2008 bad debt expense of $591,258 represented over 80% of the total amount owed the Company directly and indirectly, through the operators of the affected wells where SemGroup was the purchaser of oil. On October 28, 2009, the U.S. Bankruptcy Court confirmed the Fourth Amended Joint Plan of Affiliated Debtors which set forth various settlement details for producers and interest owners. Based on the details of the plan, discussion with operators impacted and management's judgment, the Company lowered the reserve for doubtful accounts to $405,129 at September 30, 2009, resulting in $186,129 of bad debt recovery.

Provision (Benefit) for Income Taxes

In 2009, the Company recorded a benefit for income taxes of $2,568,000 as a result of a pre-tax loss of $4,973,021 as compared to a provision for income taxes of $10,894,302 in the 2008 period as a result of pre-tax income of $32,450,071. The resulting effective tax benefit rate in 2009 was 52% as compared to an effective tax provision rate of 34% in 2008. The Company's utilization of excess percentage depletion (which is a permanent tax benefit) increased the tax benefit in the 2009 period, whereas it decreased the provision for income taxes in the 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 2009 period, while reducing the effective tax rate when recording a provision for income taxes as in the 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.

With the decline in prices and the loss in 2009, the Company established a valuation allowance on certain state tax net operating loss carryforwards (NOLs) for which the Company no longer believed were more likely than not to be realized prior to expiration. This reduced the benefit recognized during 2009 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. Existing rules must be interpreted and judgments made on how the specifics of a given rule apply to the Company.

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

Oil and Natural Gas Reserves

Management considers the estimation of the Company's 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 DD&A, provision for abandonment and assessment of the need for asset impairments. On an annual basis, with a semi-annual update, the Company's Independent Consulting Petroleum Engineer, with assistance from Company staff, prepares estimates of crude oil and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. Between periods in which reserves would normally be calculated, the Company updates the reserve calculations utilizing prices current with the period. As of September 30, 2010, the Company adopted the new SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. In accordance with the new SEC rule, the estimated oil and natural gas reserves at September 30, 2010, were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month oil and natural gas price for each month within the 12-month period prior to September 30, 2010, held flat over the life of the properties. In accordance with SEC rules effective in fiscal years 2008 and 2009, current pricing of oil and natural gas on September 30, 2008 and 2009, held flat over the life of the properties was used to estimate oil and natural gas reserves as of September 30, 2008 and 2009. Based on the Company's 2010 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $1,922,212 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. However, projected future crude oil and natural gas pricing assumptions are used by management to prepare estimates of crude oil and natural gas reserves and future net cash flows used in asset impairment assessments and in formulating management's overall operating decisions.

Successful Efforts Method of Accounting

The Company has elected to utilize the successful efforts method of accounting for its oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, non producing lease impairment, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized by property using the unit-of-production method 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 significantly less than 10% of the Company's total expenditures for oil and natural gas properties. This accounting method may yield significantly different operating results than the full cost method.

Derivative contracts

The Company entered into costless collar arrangements (all of which expired in first quarter 2009), 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 for payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price. These contracts cover only a portion of the Company's 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 expose the Company to risk of financial loss and may limit the benefit of future increases in prices. All of the Company's derivative contracts are with Bank of Oklahoma and are unsecured.

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 and meeting the effectiveness guidelines, 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. At September 30, 2010, the Company had no derivative contracts designated as cash flow hedges.

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 we believe is most commonly used by the market participants (currently 10%). 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 significant reduction in oil and natural gas prices (which are reviewed quarterly) or a decline in reserve volumes (which are re-evaluated semi-annually) would likely lead to additional impairment that may be material to the Company. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, the Company cannot predict when or if future impairment charges will be recorded.

Non-producing oil and natural gas leases are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties' costs, which the Company believes will not be transferred to proved properties over the remaining lives of the leases. Impairment loss is charged to exploration costs when recognized. As of September 30, 2010, the remaining carrying cost of non-producing oil and natural gas leases was $786,976.

Oil and Natural Gas Sales Revenue Accrual

The Company does not operate any of its oil and natural gas properties and, therefore, receives actual oil and natural gas sales volumes and prices (in the normal course of business) over a month later than the information is available to the operators of the wells. This being the case, 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 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. To calculate the exact excess percentage depletion allowance, a well-by-well calculation is, and can only be, performed at the end of each fiscal year. During interim periods, a high-level estimate is made taking into account historical data and current pricing. 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.

Refundable Production Taxes Accrual

The state of Oklahoma allows for refunds of production taxes on wells that are horizontally drilled. In order to qualify as a horizontally drilled well, the well "has completed in a manner which encounters and subsequently produces from a geological formation at an angle in excess of seventy (70) degrees from the vertical and which laterally penetrates a minimum of one hundred and fifty (150) feet into the pay zone of the formation." An operator has 18 months after a given tax year to file the appropriate forms with the Oklahoma Tax Commission (OTC) requesting the refund of production taxes. The refund is limited to 48 months from first sales or well payout, whichever comes first. Horizontal drilling in Oklahoma over the past four years has resulted in the addition of numerous wells that qualify for the Oklahoma horizontal exemption, thus increasing the Company's oil and natural gas sales subject to the accrual.

The Company does not operate any of its oil and natural gas properties and thus must rely on oil and natural gas sales and drilling information from the operators. The Company utilizes payment remittances from operators to estimate its refundable production tax accrual at the end of each quarterly period. The refundable production tax accrual can be impacted by many variables, including subsequent revenue adjustments received from operators and an operator's failure to file timely with the OTC requesting refunds. These variables could lead to an over or under accrual of production taxes at the end of any particular period. Based on historical experience, the estimated accrual has been materially accurate.

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 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Oil and natural gas prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of natural gas and oil price trends, and there remains a rather wide divergence in the opinions held by some in the industry. Being primarily a natural gas producer, the Company is more significantly impacted by changes in natural gas prices than by changes in oil or natural gas liquids prices. Longer term natural gas prices will be determined by the supply of and demand for natural gas as well as the prices of competing fuels, such as crude oil and coal. The market price of natural gas, oil and natural gas liquids in 2011 will impact the amount of cash generated from operating activities, which will in turn impact the level of the Company's capital expenditures and production. Excluding the impact of the Company's 2011 natural gas derivative contracts (see below), based on the Company's estimated natural gas volumes for 2011, the price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $855,000 for pre-tax operating income. Based on the Company's estimated oil volumes for 2011, the price sensitivity in 2011 for each $1.00 per barrel change in wellhead oil is approximately $123,000 for pre-tax operating income.

Commodity Price Risk

The Company periodically utilizes derivative contracts to reduce its exposure to unfavorable changes in natural gas prices. The Company does not enter into these derivatives for speculative or trading purposes. As of September 30, 2010, the Company has fixed swap contracts and basis protection swaps (Refer to the "Derivatives" section of Note 1 for more detail) in place. All of our outstanding derivative contracts are with one counterparty and are unsecured. 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. For the Company's fixed price swaps as of September 30, 2010, the sensitivity of a $0.10 per Mcf change in the indexed pipelines (CEGT and PEPL) futures price is approximately $90,000 for pre-tax operating income. For the Company's basis protection swaps as of September 30, 2010, the sensitivity of a $.10 per MCF change in differential between NYMEX and the indexed pipelines (CEGT and PEPL) futures prices is approximately $453,000 for pre-tax operating income.

Financial Market Risk

Operating income could also be impacted, to a lesser extent, by changes in the market interest rates related to the Company's credit facilities. The revolving loan bears interest at the national prime rate plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%. At September 30, 2010, the Company had $0 outstanding under these facilities. At this point, the company doesn't believe that it's liquidity has been materially affected by the debt market uncertainties noted in the last few years and the Company does not believe that it's liquidity will be impacted in the near future.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Annual Report on Internal Control Over Financial Reporting

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

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

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

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

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

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2010. In making this assessment, the Company's management used the criteria set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, management has concluded that, as of September 30, 2010, the Company's internal control over financial reporting was effective based on those criteria.

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

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

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

We have audited Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Panhandle Oil and Gas Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Panhandle Oil and Gas Inc. maintained, in all material respects, effective internal control over financial reporting as of September 30, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Panhandle Oil and Gas Inc. as of September 30, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2010 and our report dated December 8, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 9, 2010

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Panhandle Oil and Gas Inc. (the Company) as of September 30, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Panhandle Oil and Gas Inc. at September 30, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2010 Panhandle Oil and Gas Inc. has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Panhandle Oil and Gas Inc.'s internal control over financial reporting as of September 30, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated December 8, 2010, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 9, 2010

Panhandle Oil and Gas Inc.
Consolidated Balance Sheets

	September 30, 2010	September 30, 2009
Assets		
Current Assets:		
Cash and cash equivalents	$ 5,597,258	$ 639,908
Oil and natural gas sales receivables, net of allowance for uncollectible accounts	9,063,002	7,747,557
Deferred income taxes	-	1,934,900
Refundable production taxes	804,120	616,668
Derivative contracts	1,481,527	-
Other	412,778	68,817
Total current assets	17,358,685	11,007,850
Properties and equipment at cost, based on successful efforts accounting:		
Producing oil and natural gas properties	207,928,578	198,076,244
Non-producing oil and natural gas properties	9,616,330	10,332,537
Furniture and fixtures	656,889	578,460
	218,201,797	208,987,241
Less accumulated depreciation, depletion, and amortization	131,983,249	112,900,027
Net properties and equipment	86,218,548	96,087,214
Investments	754,208	682,391
Derivative contracts	138,799	-
Refundable production taxes	654,599	772,177
Total assets	$ 105,124,839	$ 108,549,632

(Continued on next page)

See accompanying notes.

Panhandle Oil and Gas Inc.
Consolidated Balance Sheets

	September 30, 2010	September 30, 2009
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 5,062,806	$ 4,810,687
Derivative contracts	-	1,726,901
Deferred income taxes	354,100	53,100
Accrued income taxes and other liabilities	1,842,918	980,470
Total current liabilities	7,259,824	7,571,158
Long-term debt	-	10,384,722
Deferred income taxes	22,552,650	24,064,650
Asset retirement obligations	1,730,369	1,620,225
Derivative contracts	-	786,534
Stockholders' equity:		
Class A voting common stock, $.0166 par value; 24,000,000 shares authorized, 8,431,502 issued at September 30, 2010 and 2009	140,524	140,524
Capital in excess of par value	1,816,365	1,922,053
Deferred directors' compensation	2,222,127	1,862,499
Retained earnings	73,599,733	64,507,547
	77,778,749	68,432,623
Treasury stock, at cost; 120,560 shares at September 30, 2010, and 119,866 shares at September 30, 2009	(4,196,753)	(4,310,280)
Total stockholders' equity	73,581,996	64,122,343
Total liabilities and stockholders' equity	$ 105,124,839	$ 108,549,632

See accompanying notes.

Panhandle Oil and Gas Inc.
Consolidated Statements of Operations

	Year ended September 30,		
	2010	**2009**	**2008**
Revenues:			
Oil and natural gas (and associated natural gas liquids) sales	$ 44,068,947	$ 37,421,688	$ 69,026,785
Lease bonuses and rentals	1,120,674	188,906	167,559
Gains (losses) on derivative contracts	6,343,661	(661,828)	(940,823)
Income from partnerships	405,134	323,848	631,891
	51,938,416	37,272,614	68,885,412
Costs and expenses:			
Lease operating expenses and production taxes	9,639,864	8,897,235	10,055,762
Exploration costs	1,583,773	711,582	455,943
Depreciation, depletion, and amortization	19,222,123	28,168,933	19,784,660
Provision for impairment	605,615	2,464,520	526,380
Loss (gain) on asset sales, interest and other	(1,028,148)	(2,677,407)	14,826
General and administrative	5,594,499	4,866,044	5,006,512
Bad debt expense (recovery)	-	(185,272)	591,258
	35,617,726	42,245,635	36,435,341
Income (loss) before provision (benefit) for income taxes	16,320,690	(4,973,021)	32,450,071
Provision (benefit) for income taxes	4,901,000	(2,568,000)	10,894,302
Net income (loss)	$ 11,419,690	$ (2,405,021)	$ 21,555,769
Basic and diluted earnings per common share:			
Net income (loss)	$ 1.36	$ (0.29)	$ 2.54

See accompanying notes.

Panhandle Oil and Gas Inc.
Consolidated Statements of Stockholders' Equity

	Class A voting Common Stock Shares	Common Stock Amount	Capital in Excess of Par Value	Deferred Directors Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2007	8,431,502	$ 140,524	$ 2,146,071	$ 1,358,778	$ 50,035,998	-	$ -	$ 53,681,371
Purchase of treasury stock	-	-	-	-	-	(139,014)	(4,998,842)	(4,998,842)
Issuance of common shares to ESOP	-	-	(56,001)	-	-	7,640	274,734	218,733
Common shares to be issued to directors for services	-	-	-	247,033	-	-	-	247,033
Dividends declared ($.28 per share)	-	-	-	-	(2,355,163)	-	-	(2,355,163)
Net income	-	-	-	-	21,555,769	-	-	21,555,769
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
Issuance of treasury shares to ESOP	-	-	(168,017)	-	-	11,508	413,828	245,811
Common shares to be issued to directors for services	-	-	-	256,688	-	-	-	256,688
Dividends declared ($.28 per share)	-	-	-	-	(2,324,036)	-	-	(2,324,036)
Net loss	-	-	-	-	(2,405,021)	-	-	(2,405,021)
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
Purchase of treasury stock	-	-	-	-	-	(12,326)	(291,383)	(291,383)
Issuance of treasury shares to ESOP	-	-	(117,716)	-	-	11,632	404,910	287,194
Restricted stock awards	-	-	12,028	-	-	-	-	12,028
Common shares to be issued to directors for services	-	-	-	359,628	-	-	-	359,628
Dividends declared ($.28 per share)	-	-	-	-	(2,327,504)	-	-	(2,327,504)
Net income	-	-	-	-	11,419,690	-	-	11,419,690
Balances at September 30, 2010	8,431,502	$ 140,524	$ 1,816,365	$ 2,222,127	$ 73,599,733	(120,560)	$ (4,196,753)	$ 73,581,996

See accompanying notes.

Panhandle Oil and Gas Inc.
Consolidated Statements of Cash Flows

	Year ended September 30,		
	2010	**2009**	**2008**
Operating Activities			
Net income (loss)	$ 11,419,690	$ (2,405,021)	$ 21,555,769
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	19,827,738	30,633,453	20,311,040
Provision for deferred income taxes	777,000	(3,814,000)	9,116,000
Exploration costs	1,208,653	711,582	455,943
Net (gain) loss on sales of assets	(1,189,605)	(2,654,759)	20,632
Income from partnerships	(405,134)	(323,848)	(631,891)
Distributions received from partnerships	523,317	432,805	724,765
Other	64,555	4,708	-
Common stock contributed to ESOP	287,194	245,811	218,733
Common stock (unissued) to Directors' Deferred Compensation Plan	359,628	256,688	247,033
Restricted stock awards	12,028	-	-
Bad debt expense (recovery)	-	(185,272)	591,258
Cash provided (used) by changes in assets and liabilities:			
Oil and natural gas sales receivables	(1,315,445)	9,620,843	(9,671,136)
Fair value of dervative contracts	(4,133,761)	3,159,628	(539,277)
Refundable income taxes	-	2,162,305	(2,162,305)
Refundable production taxes	(69,874)	(921,769)	(467,076)
Other current assets	(343,961)	74,455	(25,927)
Accounts payable	(24,896)	287,883	59,921
Income taxes payable	583,625	338,511	(211,155)
Accrued liabilities	225,723	86,603	471,569
Total adjustments	16,386,785	40,115,627	18,508,127
Net cash provided by operating activities	27,806,475	37,710,606	40,063,896
Investing Activities			
Capital expenditures, including dry hole costs	(11,308,506)	(39,915,051)	(38,747,749)
Proceeds from leasing of fee mineral acreage	1,316,377	209,930	200,356
Investments in partnerships	(254,555)	(59,742)	(139,177)
Proceeds from sales of assets	401,168	3,441,871	840,398
Net cash used in investing activities	(9,845,516)	(36,322,992)	(37,846,172)

(Continued on next page)

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

	Year ended September 30,		
	2010	**2009**	**2008**
Financing Activities			
Borrowings under debt agreement	$ 10,799,814	$ 49,027,225	$ 47,281,411
Payments of loan principal	(21,184,536)	(48,346,603)	(42,238,782)
Purchases of treasury stock	(291,383)	-	(4,998,842)
Payments of dividends	(2,327,504)	(2,324,036)	(2,355,163)
Net cash used in financing activities	(13,003,609)	(1,643,414)	(2,311,376)
Increase (decrease) in cash and cash equivalents	4,957,350	(255,800)	(93,652)
Cash and cash equivalents at beginning of year	639,908	895,708	989,360
Cash and cash equivalents at end of year	$ 5,597,258	$ 639,908	$ 895,708
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$ 60,912	$ -	$ 23,212
Income taxes paid, net of refunds received	$ 3,530,718	$ (1,261,808)	$ 4,145,122
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$ 110,144	$ 95,076	$ 151,998
Gross additions to properties and equipment	$ 11,585,521	$ 28,540,290	$ 52,812,138
Net (increase) decrease in accounts payable for properties and equipment additions	(277,015)	11,374,761	(14,064,389)
Capital expenditures, including dry hole costs	$ 11,308,506	$ 39,915,051	$ 38,747,749

See accompanying notes.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Since its formation, the Company has been involved in the acquisition and management of fee mineral acreage and the exploration for, and development of, oil and natural gas properties, principally involving drilling wells located on the Company's mineral acreage. Panhandle's mineral properties and other oil and natural gas interests are all located in the United States, primarily in Arkansas, Kansas, New Mexico, North Dakota, Oklahoma and Texas. The Company is not the operator of any wells. The majority of the Company's oil and natural gas production is from interests in 4,989 wells located principally in Oklahoma. Approximately 83% of oil and natural gas revenues are derived from the sale of natural gas. Substantially all the Company's oil and natural gas production is sold through the operators of the wells. The Company from time to time disposes of certain non-material, non-core or small-interest oil and natural gas properties as a normal course of business.

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of Panhandle Oil and Gas Inc. and its wholly-owned subsidiaries after elimination of all material intercompany transactions.

Certain amounts (refundable production taxes, investment in partnerships, deferred income taxes and gain on asset sales, interest and other) in the prior year have been reclassified to conform to the current year presentation.

Use of Estimates

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

Of these estimates and assumptions, management considers the estimation of crude oil and natural gas reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as depreciation, depletion and amortization (DD&A) and impairment calculations. On an annual basis, with a limited scope semi-annual update, the Company's Independent Consulting Petroleum Engineer, with assistance from the Company, 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. For DD&A purposes, and as required by the guidelines and definitions established by the SEC, the 2010 estimate was based on the average price during the 12-month period prior to September 30, 2010, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. Oil and natural gas prices used for the 2008 and 2009 estimates were based on the September 30 price of each respective year. For impairment purposes, projected future crude oil and natural gas prices as estimated by management are used. Crude oil and natural gas prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future crude oil and

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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.

The Company does not operate any of its oil and natural gas properties and, therefore, receives actual oil and natural gas sales volumes and prices (in the normal course of business) over a month later than the information is available to the operators of the wells. This being the case, 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 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.

Cash and Cash Equivalents

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

Oil and Natural Gas (and associated natural gas liquids) Sales and Natural Gas Imbalances

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

The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has underproduced or overproduced its ownership percentage in a property. Under this method, a receivable or liability is recorded to the extent that an underproduced or overproduced position in a reservoir cannot be recouped through the production of remaining reserves. At September 30, 2010 and 2009, the Company had no material natural gas imbalances.

Concentration of Credit Risk

Substantially all of the Company's accounts receivable are due from purchasers of oil and natural gas or operators of the oil and natural gas properties. Oil and natural gas sales receivables are generally unsecured.

On July 22, 2008, SemGroup, L.P. and certain subsidiaries (SemGroup) filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As a result of the filing, the Company reserved $591,258 of receivables as uncollectible for substantially all of the sales of crude oil through various well operators to SemGroup during the period June 1, 2008 through July 22, 2008. The amount reserved was charged to bad debt expense in 2008. On October 28, 2009, the U.S. Bankruptcy Court confirmed the Fourth Amended Joint Plan of Affiliated Debtors, which set forth various settlement details for producers and interest owners. Based on the details of the plan, discussion with impacted

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

operators and management's judgment, the Company has lowered the reserve for doubtful accounts to $405,129 at September 30, 2009, resulting in $186,129 of bad debt recovery.

Derivative contracts entered into by the Company are also unsecured.

Oil and Natural Gas Producing Activities

The Company follows the successful efforts method of accounting for oil and natural gas producing activities. Intangible drilling and other costs of successful wells and development dry holes are capitalized and amortized. The costs of exploratory wells are initially capitalized, but charged against income if and when the well is determined to be nonproductive. Oil and natural gas mineral and leasehold costs are capitalized when incurred.

Non-producing oil and natural gas leases are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties' costs, which the Company believes will not be transferred to proved properties over the remaining lives of the leases. Impairment loss is charged to exploration costs when recognized. As of September 30, 2010, the remaining carrying cost of non-producing oil and natural gas leases was $786,976.

It is common business practice in the petroleum industry for drilling costs to be prepaid before spudding a well. The Company frequently fulfills these prepayment requirements with cash payments, but at times will utilize letters of credit to meet these obligations. As of September 30, 2010, the Company had outstanding letters of credit totaling $57,051 that expired in November 2010.

Derivatives

The Company entered into costless collar contracts (all of which expired in first quarter 2009), fixed swap contracts and basis protection swaps. These instruments 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 payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. Fixed swap contracts set a fixed price and provide payments to the Company if the index price is below the fixed price, or require payments by the Company if the index price is above the fixed price. 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 contracts cover only a portion of the Company's natural gas production and provide only partial price protection against declines in natural gas prices. These derivative instruments expose the Company to risk of financial loss and may limit the benefit of future increases in prices. All of the Company's derivative contracts are with Bank of

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 swaps		
March - December, 2009	60,000 Mmbtu	CEGT
April - December, 2009	100,000 Mmbtu	CEGT
May - December, 2009	70,000 Mmbtu	CEGT
July - December, 2009	70,000 Mmbtu	PEPL
January - December, 2010	100,000 Mmbtu	CEGT
January - December, 2010	50,000 Mmbtu	CEGT
January - December, 2010	100,000 Mmbtu	PEPL
January - December, 2010	50,000 Mmbtu	PEPL

(1) CEGT - Centerpoint Energy Gas Transmission's East pipeline in Oklahoma
PEPL - Panhandle Eastern Pipeline Company's Texas/Oklahoma mainline

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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

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

(1) CEGT - Centerpoint Energy Gas Transmission's East pipeline in Oklahoma
PEPL - Panhandle Eastern Pipeline Company's Texas/Oklahoma mainline

While the Company believes that its derivative contracts are effective in achieving the risk management objective for which they were intended, the Company has elected not to complete all of the documentation requirements necessary to permit these derivative contracts to be accounted for as cash flow hedges. The Company's fair value of derivative contracts was an asset of $1,620,326 as of September 30, 2010, and a liability of $2,513,435 as of September 30, 2009. Realized and unrealized gains and (losses) are scheduled below:

Gains (losses) on natural gas derivative contracts	Fiscal year ended 9/30/2010	9/30/2009	9/30/2008
Realized	$ 2,209,900	$ 2,497,800	$ (1,480,100)
Increase (decrease) in fair value	4,133,761	(3,159,628)	539,277
Total	$ 6,343,661	$ (661,828)	$ (940,823)

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 September 30, 2010 and September 30, 2009:

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

	Balance Sheet Location	9/30/2010 Fair Value	9/30/2009 Fair Value
Asset Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$ 1,481,527	$ -
Commodity contracts	Long-term derivative contracts	138,799	-
Total Asset Derivatives (a)		$ 1,620,326	$ -
Liability Derivatives:			
Derivatives not designated as Hedging Instruments:			
Commodity contracts	Short-term derivative contracts	$ -	$ 1,726,901
Commodity contracts	Long-term derivative contracts	-	786,534
Total Liability Derivatives (a)		$ -	$ 2,513,435

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

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

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 September 30, 2010.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative Contracts - Swaps	-	$ 1,620,326	-	$ 1,620,326

Level 2 – Market Approach - The fair values of the Company's natural gas swaps are based on a third-party pricing model which utilizes inputs that are either readily available in the public market, such as natural gas curves, or can be corroborated from active markets. These values are based upon, among other things, future prices and time to maturity. These values are then compared to the values given by our counterparties for reasonableness.

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

	Total Losses for the Year Ended September 30, 2010	
Impairments:		
Producing Properties	$ 605,615	(a)

(a) At the end of each quarter, the Company assessed the carrying value of its producing properties for impairment. This assessment utilized estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of future oil and natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs and an applicable discount rate commensurate with risk of the underlying cash flow estimates. These assessments identified certain properties with carrying value in excess of their calculated fair values. As a result, the Company recorded $605,615 in impairment charges during 2010.

Fair Values of Financial Instruments

The carrying amounts reported in the balance sheets for cash and cash equivalents, receivables, derivative contracts, 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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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.

Depreciation, Depletion, Amortization and Impairment

Depreciation, depletion and amortization of the costs of producing oil and natural gas properties are generally computed using the units of production method primarily on a separate property basis using proved or proved developed reserves, as applicable, as estimated by the Company's Independent Consulting Petroleum Engineer. Depreciation of furniture and fixtures is computed using the straight-line method over estimated productive lives of five to eight years.

Non-producing oil and natural gas properties include non-producing minerals, which had a net book value of $4,346,191 and $4,771,926 at September 30, 2010 and 2009, respectively, consisting of perpetual ownership of mineral interests in several states, with 90% of the acreage in Arkansas, New Mexico, North Dakota, Oklahoma and Texas. As mentioned, these mineral rights are perpetual and have been accumulated over the 84 year life of the Company. There are approximately 204,460 net acres of non-producing minerals in over 7,000 tracts owned by the Company. An average tract contains approximately 29 acres, and the average cost per acre is $39. Since inception, the Company has continually generated an interest in several thousand oil and natural gas wells using its ownership of the fee mineral acres as an ownership basis. There continues to be significant drilling activity each year on these mineral interests. Non-producing minerals are being amortized straight-line over a 33 year period. These assets are considered a long-term investment by the Company; as they do not expire (as do oil and natural gas leases). Given the above, it was concluded that a long-term amortization was appropriate and that 33 years, based on past history and experience, was an appropriate period. Due to the fact that the minerals consist of a large number of properties, whose costs are not individually significant, and because virtually all are in the Company's core operating areas, the minerals are being amortized on an aggregate basis.

The Company recognizes impairment losses for long-lived assets when indicators of impairment are present and the undiscounted cash flows are not sufficient to recover the assets' carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted cash flow as estimated by the Company's Independent Consulting Petroleum Engineer. The Company's estimate of fair value of its oil and natural gas properties at September 30, 2010 is based on the best information available as of that date, including estimates of forward oil and natural gas prices and costs. The Company's oil and natural gas properties were reviewed for impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $605,615, $2,464,520 and $526,380 respectively, for 2010, 2009 and 2008. A significant 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.

Capitalized Interest

During 2010, 2009 and 2008, interest of $104,100, $455,516 and $144,520, respectively, was included in the Company's capital expenditures. Interest of $60,912, $6,946 and $44,346, respectively, was charged to expense during those periods. Interest is capitalized using a weighted average interest rate

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

based on the Company's outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using units of production method.

Investments

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

Asset Retirement Obligations

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

The following table shows the activity for the year ended September 30, 2010 and 2009 relating to the Company's retirement obligation for plugging liability:

	Plugging Liability
Plugging Liability as of September 30, 2009	$ 1,620,225
Accretion of Discount	106,093
New Wells Placed on Production	20,476
Wells Sold or Plugged	(16,425)
Plugging Liability as of September 30, 2010	$ 1,730,369
Plugging Liability as of September 30, 2008	$ 1,504,411
Accretion of Discount	104,991
New Wells Placed on Production	118,371
Wells Sold or Plugged	(107,548)
Plugging Liability as of September 30, 2009	$ 1,620,225

Environmental Costs

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays; however, to date the Company's cost of compliance has been insignificant. The Company does not believe the existence of current

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

environmental laws or interpretations thereof will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future effects on the Company of new laws or interpretations thereof. Since the Company does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by others, with Panhandle being responsible for its proportionate share of the costs involved. Panhandle carries liability insurance and pollution control coverage. However, all risks are not insured due to the availability and cost of insurance.

Environmental liabilities, which historically have not been material, are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At September 30, 2010 and 2009, there were no such costs accrued.

Earnings (Loss) Per Share of Common Stock

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

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

Share-based Compensation

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

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

Restricted stock awards to certain officers during 2010 provide for vesting at the end of five years from the date of the awards. The fair value of the awards is ratably expensed over the vesting period in accordance with accounting guidance.

Income Taxes

The estimation of amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations, as well as the completion of complex calculations, including the determination of the Company's percentage depletion deduction. Although the Company's management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

pending and new tax matters. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of the Company's assets and liabilities.

On October 1, 2007, the Company adopted the guidelines on accounting for income tax uncertainties; the impact was not material. The guidelines prescribe 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 fiscal years prior to 2007.

The Company includes interest assessed by the taxing authorities in "Interest expense" and penalties related to income taxes in "General and administrative expense" on its Consolidated Statements of Operations. For fiscal September 30, 2010, 2009 and 2008, the Company recorded no interest or penalties; as the Company does not believe it has any significant uncertain tax positions.

New Accounting Standards

In January 2010, the FASB updated its oil and natural gas estimation and disclosure requirements to align its requirements with the SEC's modernized oil and natural gas reporting rules, which are effective for annual reports on Form 10−K for fiscal years ending on or after December 31, 2009. The update includes the following changes: (1) permitting use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; (2) enabling companies to additionally disclose their probable and possible reserves to investors, in addition to their proved reserves; (3) allowing previously excluded resources, such as oil sands, to be classified as oil and natural gas reserves rather than mining reserves; (4) requiring companies to report the independence and qualifications of a preparer or auditor, based on current Society of Petroleum Engineers criteria; (5) requiring the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and (6) requiring companies to report oil and natural gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The update must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. This accounting guidance has been adopted on a prospective basis beginning in the fourth quarter of 2010. See Note 10 for disclosures regarding our natural gas and oil reserves.

The Company is not able to disclose the effects resulting from the implementation of these changes on the financial statements or on the amount of proved reserves and disclosed quantities. In order to accurately report the quantitative effect of applying oil and gas modernization rules, it would have been necessary for the Company to prepare two sets of reserve reports, one applying the new oil and gas modernization rules and another applying the rules in effect at September 30, 2009. The Company has interests in several thousand developed and undeveloped properties which are evaluated in the reserve estimation process. The Company has a total of eighteen employees including one petroleum engineer and one engineering tech. Staff time was not available for the engineering staff to perform necessary controls to ensure the accuracy of the report, for accounting personnel to recalculate DD&A

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

and re-test for impairment of producing properties and be able to timely prepare and file this Form 10-K with the SEC. Therefore, the Company determined that it was not practicable to perform a second reserve estimation process under the prior rules.

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.

2. COMMITMENTS

The Company leases office space in Oklahoma City, Oklahoma under the terms of an operating lease expiring in April 2012. Future minimum rental payments under the terms of the lease are $204,089 in 2011 and $119,052 in 2012. Total rent expense incurred by the Company was $203,939 in 2010, $200,627 in 2009 and $175,335 in 2008.

3. INCOME TAXES

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

	2010	**2009**	**2008**
Current:			
Federal	$ 3,950,000	$ 1,246,000	$ 1,728,000
State	174,000	-	50,302
	4,124,000	1,246,000	1,778,302
Deferred:			
Federal	708,000	(3,254,000)	8,090,000
State	69,000	(560,000)	1,026,000
	777,000	(3,814,000)	9,116,000
	$ 4,901,000	$ (2,568,000)	$ 10,894,302

3. INCOME TAXES (CONTINUED)

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

	2010	2009	2008
Provision (benefit) for income taxes at statutory rate	$ 5,712,242	$ (1,690,827)	$ 11,336,596
Percentage depletion	(684,053)	(469,962)	(1,072,282)
State income taxes, net of federal provision (benefit)	325,000	(451,440)	797,550
State net operating loss carryforward benefit	-	(154,000)	(143,000)
State net operating loss valuation allowance (release)	(278,000)	278,000	-
Other	(174,189)	(79,771)	(24,562)
	$ 4,901,000	$ (2,568,000)	$ 10,894,302

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

	2010	2009
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 24,141,021	$ 27,139,652
Derivative contracts	630,307	-
	24,771,328	27,139,652
Deferred tax assets:		
Alternative minimum tax credit carryforwards	-	2,207,810
State net operating loss carry forwards, net of valuation allowance of $278,000 in 2009	825,048	926,600
Derivative contracts	-	977,726
Deferred directors compensation, allowance for uncollectible accounts and other	1,039,530	897,766
	1,864,578	5,009,902
Net deferred tax liabilities	$ 22,906,750	$ 22,129,750

At September 30, 2010, the Company had an income tax benefit of $825,048 related to Oklahoma state income tax net operating loss (OK NOL) carryforwards expiring from 2023 to 2029. The valuation allowance of $278,000 from 2009 was reversed in the current year as it became evident that the previously reserved Oklahoma NOLs will be utilized before they expire.

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 pricing forecast and a 9% discount rate to the Company's proved reserves as calculated by the Company's Independent 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 remained $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. Effective May 20, 2009 the Company again increased the borrowing base from $25,000,000 to $35,000,000. On December 8, 2009 and May 25, 2010, Panhandle's bank reaffirmed the Company's $35,000,000 borrowing base and extended the maturity date of the credit facility to October 31, 2012. The restructured interest rate is based on national prime plus from .50% to 1.25%, or 30 day LIBOR plus from 2.00% to 2.75%, with an established interest rate floor of 4.50% annually. On August 3, 2010, the 4.50% interest rate floor was removed. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the loan value of the Company's oil and natural gas properties is advanced. Borrowings outstanding under the revolving loan amounted to $0 and $10,384,722 as of September 30, 2010 and 2009, respectively.

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 credit facility contains customary covenants which, among other things, require periodic financial and reserve reporting and limit the Company's incurrence of indebtedness, liens, dividends and acquisitions of treasury stock, and require the Company to maintain certain financial ratios. At September 30, 2010, the Company was in compliance with the covenants of the credit facility.

5. SHAREHOLDERS' EQUITY

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. These programs were completed in 2008. Upon approval by the shareholders of the Company's 2010 Restricted Stock Plan on March 11, 2010, the board of directors approved repurchase of up to $1.5 million of the Company's common stock, from time to time, equal to the aggregate number of shares of common stock awarded pursuant to the Company's 2010 Restricted Stock Plan, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors. Approximately 40,000 shares are expected to be repurchased during fiscal year 2011. As of September 30, 2010, approximately $291,000 had been spent under the current program to purchase 12,326 shares. The shares are held in treasury and are accounted for using the cost method. At September 30, 2010 and 2009, 11,632 and 11,508 (respectively) treasury shares were contributed to the Company's ESOP on behalf of the ESOP participants.

6. EARNINGS PER SHARE

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

	Year ended September 30, 2010	2009	2008
Numerator for basic and diluted earnings per share:			
Net income (loss)	$ 11,419,690	$ (2,405,021)	$ 21,555,769
Denominator for basic and diluted earnings per share - weighted average shares (including for 2010, 2009 and 2008, unissued, vested directors' shares of 111,491, 97,177 and 85,504, respectively)	8,422,387	8,397,337	8,492,378

7. EMPLOYEE STOCK OWNERSHIP PLAN

The Company's ESOP was established in 1984 and is a tax qualified, defined contribution plan, and serves as the Company's sole retirement plan for its employees. Company contributions are made at the discretion of the Board of Directors and, to date, all contributions have been made in shares of Company common stock. The Company contributions are allocated to all ESOP participants in proportion to their salaries for the plan year and 100% vesting occurs after three years of service. For contributions of common stock, the Company records as expense, the fair market value of the stock at the time of contribution. The 243,149 shares of the Company's common stock held by the plan, as of September 30, 2010, are allocated to individual participant accounts, are included in the weighted average shares outstanding for purposes of earnings per share computations and receive dividends. Contributions to the plan consisted of:

Year	Shares	Amount
2010	11,632	$ 287,194
2009	11,508	$ 245,811
2008	7,640	$ 218,733

8. DEFERRED COMPENSATION PLAN FOR DIRECTORS

The Panhandle Oil and Gas Inc. Deferred Compensation Plan for Non-Employee Directors (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. As of September 30, 2010, there were 114,323 shares (99,560 shares at September 30, 2009) included in the Plan. The deferred balance outstanding at September 30, 2010 under the Plan was $2,222,127 ($1,862,499 at September 30, 2009). Expense totaling $359,628, $256,688 and $247,033 was charged to the Company's results of operations for the years ended September 30, 2010, 2009 and 2008, respectively, and is included in general and administrative expense in the accompanying Statement of Operations.

9. RESTRICTED STOCK PLAN

On March 11, 2010, shareholders approved the Panhandle Oil and Gas Inc. 2010 Restricted Stock Plan (2010 Stock Plan), which made available 100,000 shares of Common Stock to provide a long-term component to the Company's total compensation package for its officers and to further align the interest of its officers with those of its shareholders. The 2010 Stock Plan is designed to provide as much flexibility as possible for future grants of restricted stock so that the Company can respond as necessary to provide competitive compensation in order to retain, attract and motivate officers of the Company and to align their interests with those of the Company's shareholders.

In June 2010, the Company awarded 8,500 shares of the Company's Common Stock as restricted stock to certain officers. The restricted stock vests at the end of five years and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. Dividends expected to be paid are $.07 per share each quarter. The fair value of the shares at the time of their award, based on the closing price of the shares on their award date, was $240,550 and will be recognized as compensation expense ratably over the vesting period. The compensation expense recognized as a part of G&A expense in 2010 was $12,028.

A summary of the status of unvested shares of restricted stock awards and changes during 2010 is presented below:

	Unvested Restricted Shares	**Weighted Average Grant-Date Fair Value**
Unvested shares as of October 1, 2009	-	$ -
Granted	8,500	$ 28.30
Vested	-	$ -
Forfeited	-	$ -
Unvested shares as of September 30, 2010	8,500	$ 28.30

No vesting of restricted stock occurred during 2010. As of September 30, 2010, there was $228,522 of total unrecognized compensation cost related to unvested restricted stock. The cost is to be recognized over a weighted average period of 4.75 years. Upon vesting, shares are expected to be issued out of shares held in treasury.

10. INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES

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

During 2010, 2009 and 2008, approximately 14%, 20% and 16%, respectively, of the Company's total revenues were derived from sales through Chesapeake Operating, Inc. During 2010, 2009 and 2008, approximately 11%, 14% and 17%, respectively, of the Company's total revenues were derived from sales through JMA Energy Company. During 2010, 2009 and 2008, approximately 15%, 17% and 12% of the Company's total revenues were derived from sales through Newfield Exploration.

10. INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES (CONTINUED)

Aggregate Capitalized Costs

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

	2010	2009
Producing properties	$ 207,928,578	$ 198,076,244
Non-producing minerals	7,744,767	8,036,236
Non-producing leasehold	1,360,264	2,241,232
Exploratory wells in progress	511,299	55,069
	217,544,908	208,408,781
Accumulated depreciation, depletion and amortization	(131,529,373)	(112,505,428)
Net capitalized costs	$ 86,015,535	$ 95,903,353

Costs Incurred

During the reporting period, the Company incurred the following costs in oil and natural gas producing activities:

	2010	2009	2008
Property acquisition costs	$ 742,005	$ 382,239	$ 2,359,988
Exploration costs	530,931	1,647,456	1,887,182
Development costs	10,685,088	26,411,704	48,503,130
	$ 11,958,024	$ 28,441,399	$ 52,750,300

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

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

Proved oil and natural gas reserves are those quantities of oil and natural gas which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced or the operator

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

must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas calculated the Company’s oil and natural gas reserves as of September 30, 2010 (see Exhibits 23 and 99). Reserves as of September 30, 2008 and 2009 were calculated by Pinnacle Energy Services, L.L.C. of Oklahoma City, Oklahoma.

The Company’s net proved oil and natural gas reserves, all of which are located in the United States, as of September 30, 2010, 2009 and 2008, have been estimated by the Company’s Independent Consulting Petroleum Engineering Firms (as noted above). All studies have been prepared in accordance with regulations prescribed by the SEC and generally accepted geological and engineering methods by the petroleum industry.

All of the reserve estimates are reviewed and approved by our Vice President and COO, who reports directly to our President and CEO. Mr. Blanchard, our COO, holds a Bachelor of Science Degree in Petroleum Engineering from the University of Oklahoma. Before joining the Company, he was sole proprietor of a consulting petroleum engineering firm, spent 10 years as Vice President of the Mid-Continent business unit of Range Resources Corporation and spent several years as an engineer with Enron Oil and Gas. He is an active member of the Society of Petroleum Engineers (SPE) with over 25 years of oil and gas industry experience, including engineering assignments in several field locations.

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

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

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

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

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

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

Estimated Quantities of Proved Oil and Natural Gas Reserves

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

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

	Proved Reserves	
	Oil (Mbarrels)	Natural Gas (Mmcf)
September 30, 2007	823	37,006
Revisions of previous estimates	136	117
Divestitures	(1)	(83)
Extensions and discoveries	164	18,039
Production	(132)	(6,928)
September 30, 2008	990	48,151
Revisions of previous estimates	(30)	589
Divestitures	(4)	(317)
Extensions and discoveries	93	14,715
Production	(128)	(9,110)
September 30, 2009	921	54,028
Revisions of previous estimates	48	15,763
Divestitures	(1)	(8)
Extensions and discoveries	59	36,690
Production	(102)	(8,303)
September 30, 2010	925	98,170

The prices used to calculate reserves and future cash flows from reserves for oil and natural gas, respectively, were as follows: September 30, 2010 - $69.23/Bbl, $4.33/Mcf; September 30, 2009 - $66.96/Bbl, $2.86/Mcf; September 30, 2008 - $97.74/Bbl, $4.51/Mcf (these natural gas prices are representative of local pipelines in Oklahoma).

The revisions of previous estimates were primarily the result of positive performance revisions, which were principally attributable to properties in the southeast Oklahoma Woodford Shale and the Arkansas Fayetteville Shale. The revisions are principally the result of actual well performance on both new and existing wells exceeding the performance projections in the prior estimates. The improved performance in the new wells can be attributed to the drilling of longer horizontal laterals as well as enhanced fracture stimulation techniques. Increased oil and natural gas prices also contributed to the increase in reserves.

Extensions and discoveries are principally attributable to: (1) the Company’s drilling expenditures in ongoing development of unconventional natural gas plays utilizing horizontal drilling, including the southeast Oklahoma Woodford Shale and Arkansas Fayetteville Shale; (2) the Company’s drilling expenditures in development of an unconventional natural gas and natural gas liquids-rich play utilizing horizontal drilling, the Anadarko Basin (Cana) Woodford Shale: (3) the Company’s drilling expenditures in development of conventional natural gas, natural gas liquids-rich and oil plays utilizing horizontal

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

drilling and to a lesser extent vertical drilling, primarily in western Oklahoma and the Texas Panhandle; and (4) a significant addition of proven undeveloped reserves resulting from the implementation of the Securities and Exchange Commission's "Modernization of Oil and Gas Reporting Rules". Increased oil and natural gas prices also contributed to the increase in reserves.

	Proved Developed Reserves		**Proved Undeveloped Reserves**	
	Oil (Mbarrels)	**Natural Gas (Mmcf)**	**Oil (Mbarrels)**	**Natural Gas (Mmcf)**
September 30, 2008	895	35,970	95	12,181
September 30, 2009	883	45,036	38	8,991
September 30, 2010	861	57,344	64	40,826

The above reserve numbers exclude approximately 2.9 Bcf of CO_2 gas reserves for the year ended September 30, 2008. These reserves were sold in the fourth quarter of 2009.

The following details the changes in proved undeveloped reserves for 2010 (Mmcfe):

Beginning proved undeveloped reserves	9,219
Proved undeveloped reserves transferred to proved developed	(3,545)
Revisions	3,060
Extensions and discoveries	32,476
Ending proved undeveloped reserves	41,210

During 2010, various exploration and development drilling evaluations were completed. Approximately $10.7 million was spent during 2010 related to undeveloped reserves that were transferred to developed reserves. Estimated future development costs relating to the development of proved undeveloped reserves are projected to be approximately $12 million in 2011, $14 million in 2012 and $9 million in 2013. All proved undeveloped drilling locations are expected to be drilled prior to the end of 2015.

Standardized Measure of Discounted Future Net Cash Flows

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

Future cash inflows and future production and development costs as of September 30, 2010 are determined by applying the trailing unweighted 12-month arithmetic average of the first-day-of-the-month oil and natural gas prices and year-end costs to the estimated quantities of natural gas and oil to be

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

produced. Actual future prices and costs may be materially higher or lower than the unweighted 12-month arithmetic average of the first-day-of-the-month oil and natural gas prices and year-end costs used. Amounts as of September 30, 2008 and 2009 were determined using year-end prices and costs. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year. Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor. The assumptions used to compute the standardized measure are those prescribed by the FASB and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

	2010	**2009**	**2008**
Future cash inflows	$ 489,691,155	$ 216,181,210	$ 318,004,410
Future production costs	148,727,914	62,102,230	79,668,500
Future development costs	52,975,820	5,412,470	19,364,580
Asset retirement obligation	1,730,369	1,620,225	1,504,411
Future income tax expense	99,118,090	43,832,666	68,086,237
Future net cash flows	187,138,962	103,213,619	149,380,682
10% annual discount	114,638,553	49,467,111	70,585,957
Standardized measure of discounted future net cash flows	$ 72,500,409	$ 53,746,508	$ 78,794,725

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

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

	2010	2009	2008
Beginning of year	$ 53,746,508	$ 78,794,725	$ 77,029,122
Changes resulting from:			
Sales of oil and natural gas, net of production costs (1)	(34,429,083)	(28,524,453)	(58,971,023)
Net change in sales prices and production costs	30,806,970	(59,790,799)	9,274,593
Net change in future development costs	(26,093,254)	7,769,930	(5,841,539)
Net change in asset retirement obligation	(48,185)	(63,536)	(142,847)
Extensions and discoveries	53,274,047	21,677,448	46,677,163
Revisions of quantity estimates	28,946,810	587,215	2,417,457
Divestitures of reserves-in-place	(15,706)	(480,535)	(208,419)
Accretion of discount	8,066,959	12,110,733	11,626,875
Net change in income taxes	(25,807,417)	15,389,517	(3,072,975)
Change in timing and other, net	(15,947,240)	6,276,263	6,318
Net change	18,753,901	(25,048,217)	1,765,603
End of year	$ 72,500,409	$ 53,746,508	$ 78,794,725

(1) Sales of natural gas includes associated natural gas liquids

12. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

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

	Fiscal 2010			
	Quarter Ended			
	December 31	**March 31**	**June 30**	**September 30**
Revenues	$ 12,321,352	$ 16,856,884	$ 10,461,870	$ 12,298,310
Income before provision for income taxes	2,411,378	6,964,566	2,264,300	4,680,446
Net income	1,708,378	5,163,566	1,511,300	3,036,446
Earnings per share	$ 0.20	$ 0.61	$ 0.18	$ 0.36

	Fiscal 2009			
	Quarter Ended			
	December 31	**March 31**	**June 30**	**September 30**
Revenues	$ 11,261,642	$ 8,835,617	$ 8,665,216	$ 8,510,139
Income (loss) before provision for income taxes	(1,053,629)	(1,971,256)	(2,001,512)	53,376
Net income (loss)	(874,629)	(945,256)	(928,512)	343,376
Earnings (loss) per share	$ (0.10)	$ (0.11)	$ (0.11)	$ 0.04

13. SUBSEQUENT EVENTS

Effective December 6, 2010, the Company amended its revolving credit facility with BOK to increase the revolving loan amount to $80,000,000 (the borrowing base remains at $35,000,000) and change the maturity date to November 30, 2014. There was no change to the current interest rates as discussed in Note 4.

ITEM 9 CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

NONE

ITEM 9A CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE 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.

(b) MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company’s management is responsible for establishing and maintaining adequate “internal control over financial reporting”, as such term is defined in Exchange Act Rule 13a-15(f). The Company’s management, including the President/CEO and Vice President/CFO, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the Company’s management concluded that its internal control over financial reporting was effective as of September 30, 2010.

(c) CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

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 ended September 30, 2010 or subsequent to the date the assessment was completed.

ITEM 9B OTHER INFORMATION

None

PART III

The information called for by Part III of Form 10-K (Item 10 – Directors and Executive Officers of the Registrant, Item 11 – Executive Compensation, Item 12 – Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13 – Certain Relationships and Related Transactions, and Item 14 – Principal Accountant Fees and Services), is incorporated by reference from the Company's definitive proxy statement, which will be filed with the SEC within 120 days after the end of the fiscal year to which this report relates.

PART IV

ITEM 15 EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

FINANCIAL STATEMENT SCHEDULES

The Company has omitted all other schedules because the conditions requiring their filing do not exist or because the required information appears in the Company's Consolidated Financial Statements, including the notes to those statements.

EXHIBITS

(3) Amended Certificate of Incorporation (incorporated by reference to Exhibit attached to Form 10 filed January 27, 1980, and to Forms 8-K dated June 1, 1982, December 3, 1982, to Form 10-QSB dated March 31, 1999, and to Form 10-Q dated March 31, 2007)
By-Laws as amended (incorporated by reference to Form 8-K dated October 31, 1994)
By-Laws as amended (incorporated by reference to Form 8-K dated February 24, 2006)
By-Laws as amended (incorporated by reference to Form 8-K dated October 29, 2008)
(4) Instruments defining the rights of security holders (incorporated by reference to Certificate of Incorporation and By-Laws listed above)
*(10) Agreement indemnifying directors and officers (incorporated by reference to Form 10-K dated September 30, 1989, and Form 8-K dated June 15, 2007)
*(10) Agreements to provide certain severance payments and benefits to executive officers should a Change-in-Control occur as defined by the agreements (incorporated by reference to Form 8-K dated September 4, 2007)
(21) Subsidiaries of the Registrant
(23) Consent of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(31.1) Certification of Chief Executive Officer
(31.2) Certification of Chief Financial Officer
(32.1) Certification of Chief Executive Officer
(32.2) Certification of Chief Financial Officer
(99) Report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants

* Indicates management contract or compensatory plan or arrangement

REPORTS ON FORM 8-K

Dated September 14, 2010; item 8.01 – Other Events

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

PANHANDLE OIL AND GAS INC.

By: /s/ Michael C. Coffman
Michael C. Coffman
President;
Chief Executive Officer

Date: December 9, 2010

By: /s/ Lonnie J. Lowry
Lonnie J. Lowry
Vice President;
Chief Financial Officer

Date: December 9, 2010

By: /s/ Robb P. Winfield
Robb P. Winfield
Controller;
Chief Accounting Officer

Date: December 9, 2010

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ Bruce M. Bell
Bruce M. Bell, Director

Date December 9, 2010

/s/ E. Chris Kauffman
E. Chris Kauffman, Director

Date December 9, 2010

/s/ Duke R. Ligon
Duke R. Ligon, Director

Date December 9, 2010

/s/ Robert O. Lorenz
Robert O. Lorenz, Lead Independent Director

Date December 9, 2010

/s/ Robert A. Reece
Robert A. Reece, Director

Date December 9, 2010

/s/ Robert E. Robotti
Robert E. Robotti, Director

Date December 9, 2010

/s/ Darryl G. Smette
Darryl G. Smette, Director

Date December 9, 2010

/s/ H. Grant Swartzwelder
H. Grant Swartzwelder, Director

Date December 9, 2010

EXHIBIT 21

SUBSIDIARIES OF PANHANDLE OIL AND GAS INC.
AT SEPTEMBER 30, 2010

The following table sets forth certain information with respect to Panhandle's subsidiaries:

Corporation

Wood Oil Company

Wood Oil Company was incorporated in Oklahoma and is included in Panhandle's consolidated financial statements. Effective October 1, 2001, 100% of Wood Oil Company’s outstanding stock was acquired by Panhandle.

EXHIBIT 23

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

December 8, 2010

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

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to the inclusion of our Letter Report, dated September 30, 2010, as attached as Exhibit 99 to the Annual Report on Form 10-K of Panhandle Oil and Gas Inc., and to the inclusion of information from "Appraisal Report as of September 30, 2010, on Certain Properties owned by Panhandle Oil and Gas Inc." in the sections "Proved Reserves," and "Supplementary Information on Oil and Natural Gas Reserves (Unaudited)" in the Annual Report on Form 10-K of Panhandle Oil and Gas Inc.

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

EXHIBIT 31.1

CERTIFICATION

I, Michael C. Coffman, certify that:

1. I have reviewed this annual report on Form 10-K of Panhandle Oil and Gas Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a). designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b). designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c). evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d). disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a). all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b). any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Michael C. Coffman
Michael C. Coffman
Chief Executive Officer
Date: December 9, 2010

EXHIBIT 31.2

CERTIFICATION

I, Lonnie J. Lowry, certify that:

1. I have reviewed this annual report on Form 10-K of Panhandle Oil and Gas Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a). designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b). designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c). evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d). disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a). all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b). any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Lonnie J. Lowry
Lonnie J. Lowry
Chief Financial Officer
Date: December 9, 2010

EXHIBIT 32.1

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

CERTIFICATION OF CHIEF EXECUTIVE OFFICER REGARDING PERIODIC REPORT CONTAINING FINANCIAL STATEMENTS

I, Michael C. Coffman, President and Chief Executive Officer of Panhandle Oil and Gas Inc., (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify in connection with the Company's Annual Report on Form 10-K for the period that ended September 30, 2010, as filed with the Securities and Exchange Commission (the "Report") that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in this Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Michael C. Coffman
Michael C. Coffman
President &
Chief Executive Officer

December 9, 2010

EXHIBIT 32.2

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

CERTIFICATION OF CHIEF FINANCIAL OFFICER
REGARDING PERIODIC REPORT CONTAINING
FINANCIAL STATEMENTS

I, Lonnie J. Lowry, Vice President and Chief Financial Officer of Panhandle Oil and Gas Inc., (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify in connection with the Company's Annual Report on Form 10-K for the period that ended September 30, 2010, as filed with the Securities and Exchange Commission (the "Report") that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in this Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Lonnie J. Lowry
Lonnie J. Lowry
Vice President &
Chief Financial Officer

December 9, 2010

EXHIBIT 99

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

This is a digital representation of a DeGolyer and MacNaughton report.

Each file contained herein is intended to be a manifestation of certain data in the subject report and as such is subject to the definitions, qualifications, explanations, conclusions, and other conditions thereof. The information and data contained in each file may be subject to misinterpretation; therefore, the signed and bound copy of this report should be considered the only authoritative source of such information.

DEGOLYER AND MACNAUGHTON

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

September 30, 2010

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

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved crude oil, condensate, and natural gas reserves, as of September 30, 2010, of certain properties owned by Panhandle Oil and Gas Inc. (Panhandle) and Wood Oil Company (Wood), a wholly owned subsidiary of Panhandle. The properties appraised consist of working and royalty interests located in the states of Arkansas, Kansas, New Mexico, Oklahoma, and Texas. Panhandle and Wood have represented that these properties account for 100 percent of proved reserves.

Estimates of proved reserves presented in this report have been prepared in compliance with the regulations promulgated by the United States Securities and Exchange Commission (SEC). These reserves definitions are discussed in detail under the Definition of Reserves heading of this letter.

Reserves included herein are expressed as gross and net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after September 30, 2010. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Panhandle and Wood after deducting all royalties and interests owned by others. Gas quantities shown herein are sales gas quantities and are expressed at a temperature base of 60 degrees Fahrenheit and at the legal pressure base of the state in which the interest is located. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Condensate reserves estimated herein are those to be recovered by normal field separation.

Values of proved reserves shown herein are expressed in terms of estimated future gross revenue, future net revenue, and present worth of future net revenue. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating expenses, and investments from future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at 10 percent per annum over the expected period of realization.

Estimates of oil, condensate, and natural gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this report were obtained from Panhandle and Wood, from records on file with the appropriate regulatory agencies, and from public sources. Additionally, this information includes data supplied by Petroleum Information/Dwights LLC; Copyright 2010 Petroleum Information/Dwights LLC. In the preparation of this report we have relied, without independent verification, upon such information furnished by Panhandle with respect to property interests appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

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

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

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

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Primary Economic Assumptions

Revenue values in this report were estimated using the initial prices and costs specified by Panhandle and Wood. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The initial and future prices used in this report are adjusted to prices on September 30, 2010. The following economic assumptions were used for estimating existing and future prices and costs:

Oil, Condensate, and Natural Gas Prices

Oil and condensate price differentials for each property were provided by Panhandle and Wood. The prices were calculated using these differentials to a posted WTI price of $77.63 per barrel and were held constant for the lives of the properties. The WTI price of $77.63 is the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to September 30, 2010.

Gas price differentials for each property were provided by Panhandle and Wood. The prices were calculated using these differentials to a Henry Hub price of $4.49 per million British thermal units (MMBtu) and were held constant for the lives of the properties. The Henry Hub gas price of $4.49 per MMBtu is the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to September 30, 2010.

The weighted average prices over the lives of the properties were $69.23 per barrel of oil and $4.33 per thousand cubic feet of gas.

Operating Expenses and Capital Costs

Estimates of operating expenses and capital costs based on current costs were used for the lives of the properties with no increases in the future based on inflation. In certain cases, future costs, either higher or lower than current costs, may have been used because of anticipated changes in operating conditions. Future capital costs were estimated using 2010 values and were not adjusted for inflation.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the September 30, 2010, estimated oil and gas volumes. The reserves estimated in this report can be produced under current regulatory guidelines.

Summary Reserves and Revenues

The estimates of the combined net proved reserves attributable to Panhandle and Wood from the properties appraised, as of September 30, 2010, are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Oil and Condensate (Mbbl)	Sales Gas (MMcf)
Proved		
Developed Producing	848	56,456
Developed Nonproducing	14	888
Undeveloped	63	40,826
Total Proved	**925**	**98,170**

The estimated future revenue to be derived from the production and sale of the combined proved reserves, as of September 30, 2010, of the properties appraised is summarized as follows, expressed in thousands of dollars (M$):

	Proved			
	Developed Producing	Developed Nonproducing	Undeveloped	Total Proved
Future Gross Revenue, M$	303,218	5,035	181,439	489,692
Production & Ad Valorem Taxes, M$	21,394	362	8,484	30,240
Operating Expenses, M$	81,090	1,131	36,267	118,488
Capital Costs, M$	0	489	52,487	52,976
Future Net Revenue, M$	200,734	3,053	84,201	287,988
Present Worth at 10 Percent, M$	103,343	685	21,960	125,988

Note: Future income taxes have not been taken into account in the preparation of these estimates.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the Securities and Exchange Commission; provided, however, future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 70 years. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Panhandle. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Panhandle. DeGolyer and MacNaughton has used all assumptions, data, methods, and procedures that it considers necessary to prepare this report.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Paul J. Szatkowski PE

Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Paul J. Szatkowski, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Panhandle Oil and Gas Inc. dated September 30, 2010, and that I, as Senior Vice President, was responsible for the preparation of this report.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1974; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists; and that I have in excess of 36 years of experience in the oil and gas reservoir studies and reserves evaluations.

Signed: September 30, 2010

Paul J Szatkowski PE

Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton