

PANHANDLE ROYALTY CO

Form 10-K

December 13, 2006

Table of Contents

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, 2006

Commission File Number: 0-9116

PANHANDLE ROYALTY COMPANY

(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 305, 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)

AMERICAN 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 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 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. 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 Non-accelerated filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes 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, 2006, was \$141,933,276. As of December 4, 2006, 8,422,529 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 8, 2007, 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.

TABLE OF CONTENTS

	Page
<u>PART I</u>	
<u>Item 1 Business</u>	1-8
<u>Item 2 Properties</u>	8-15
<u>Item 3 Legal Proceedings</u>	15
<u>Item 4 Submission of Matters to a Vote of Security Holders</u>	15
<u>PART II</u>	
<u>Item 5 Market for Registrants Common Equity and Related Stockholder Matters</u>	16
<u>Item 6 Selected Financial Data</u>	17-18
<u>Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	18-25
<u>Item 7A Quantitative and Qualitative Disclosures about Market Risk</u>	25-26
<u>Item 8 Financial Statements and Supplementary Data</u>	26-50
<u>Item 9 Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</u>	51
<u>Item 9A Controls and Procedures</u>	51
<u>PART III</u>	
Item 10-14 Incorporated by Reference to Proxy Statement	
<u>PART IV</u>	
<u>Item 15 Exhibits, Financial Statement Schedules and Reports on Form 8-K</u>	52
<u>Signature Page</u>	53
Exhibit 21	54
Exhibit 31.1-31.2	55-56
Exhibit 32.1-32.2	57-58
<u>Subsidiaries of the Registrant</u>	
<u>Certification of Chief Executive Officer</u>	
<u>Certification of Chief Financial Officer</u>	
<u>Certification of Chief Executive Officer</u>	
<u>Certification of Chief Financial Officer</u>	

Certain defined terms as used in this report: **SEC** means the United States Securities and Exchange Commission, **Bbl** means barrel, **Bcf** means billion cubic feet, **Mcf** means thousand cubic feet, **Mcf/d** means thousand cubic feet per day, **Mcf/e** 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, **PV-10** means estimated pretax present value of future net revenues discounted at 10% using SEC rules, **gross** wells or acres are the wells or acres in which the Company has a working interest, and **net** wells or acres are determined by multiplying gross wells or acres by the Company's net revenue interest in such wells or acres. References to years 2002-2006 refer to the Company's fiscal years ended September 30 each year. **Minerals**, **mineral acres** or mineral interests refers to fee mineral acreage owned in perpetuity by the Company.

Table of Contents

PART I

ITEM 1 BUSINESS

GENERAL

Panhandle Royalty Company (Panhandle or the Company) is an Oklahoma corporation organized in 1926 as Panhandle Cooperative Royalty Company. In 1979, Panhandle Cooperative Royalty Company was merged into Panhandle. Panhandle s authorized and registered stock consisted of 100,000 shares of \$1.00 par value Class A Common Stock. In 1982, the Company split the stock on a 10-for-1 basis resulting in 1,000,000 shares of authorized Class A Common Stock. In May 1999, the Company s shareholders voted to increase the authorized Class A Common Stock to 6,000,000 shares and to split the shares on a three-for-one basis. In addition, voting rights for the shares were changed from one vote per shareholder to one vote per share. In February 2004, the Company s shareholders voted to increase the authorized Class A Common Stock to 12,000,000 shares and to split the shares on a two-for-one basis. In January 2006, the Class A Common Stock was again split on a two-for-one basis.

Since its formation, the Company has been involved in the acquisition, management and development of oil and gas properties, including wells located on the Company s mineral acreage. Panhandle s mineral properties and other oil and gas interests are located primarily in Oklahoma, New Mexico and Texas. Properties are also located in nine other states. The majority of the Company s oil and gas production is from wells located in Oklahoma. In 1988, the Company merged with New Mexico Osage Royalty Company acquiring most of its New Mexico mineral acreage.

On October 1, 2001, Panhandle acquired privately held Wood Oil Company (Wood) of Tulsa, Oklahoma. Prior to the acquisition, Wood was a privately held company engaged in oil and gas exploration and production and fee mineral ownership and owned interests in certain oil and gas and real estate partnerships and an office building in Tulsa. Wood is operating as a wholly-owned subsidiary of Panhandle. Wood and its shareholders were unrelated parties to Panhandle.

The Company s office is located at Grand Centre, Suite 305, 5400 North Grand Blvd., Oklahoma City, OK 73112 (405)948-1560, fax (405)948-2038. Its website is located at www.panra.com.

The Company makes periodic SEC reports on Forms 10-Q and Forms 10-K, the Company s annual report to shareholders and current press releases available free of charge through its website as soon as reasonably practicable after they are filed electronically with the SEC. In addition, posted on the website are copies of the various corporate governance documents. From time to time, other important disclosures to investors are provided by posting them 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 450 Fifth Street, N.W., 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 have been filed electronically with the SEC.

BUSINESS STRATEGY

The majority 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 gas holdings, including its mineral acreage and its working and royalty interests in producing wells are centered in Oklahoma with some activity in New Mexico, Texas, Arkansas and Kansas. See Item 2 Description of Properties .

(1)

Table of Contents

Exploration and development of the Company's oil and gas properties are conducted in association with operating oil and gas companies, primarily larger independent companies. The Company does not operate any of its oil and gas properties, but has been an active working interest participant for many years in wells drilled on the Company's mineral properties and in third party drilling prospects. A large percentage of the Company's recent drilling participations have been on properties in which the Company has mineral acreage and, in many cases, already owns an interest in a producing well in the unit.

PRINCIPAL PRODUCTS AND MARKETS

The Company's principal products are crude oil and natural gas. 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 properties in which it owns an interest, it relies on the operating expertise of numerous companies that operate in the areas where the Company owns interests. This expertise includes the drilling and completion of new wells, producing well operations and, in most cases, the marketing or purchasing of the well's production. Natural gas sales are principally handled by the well operator and are normally contracted on a monthly basis with third party gas marketers and pipeline companies. Payment for gas sold is received 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 from the well operator or from the crude oil purchaser.

In general, prices of oil and gas are dependent on numerous factors beyond the control of the Company, such as competition, 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 are subject to seasonal variations. The Company had not, through fiscal 2006, engaged in price hedging on its oil or gas production.

Beginning in calendar 2007 the Company has entered in hedging arrangements to reduce the Company's exposure to short-term fluctuations in the price of natural gas. The hedging arrangements apply to only a portion of the Company's production and provide only partial price protection against declines in natural gas prices. These hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in prices. A more thorough discussion of the hedging arrangements is contained in the Management's Discussion and Analysis of Financial Condition and Results of Operation section of this report contained in Item 7.

COMPETITIVE BUSINESS CONDITIONS

The oil and gas industry is highly competitive, particularly in the search for new oil and 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 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 dramatic influence on the price Panhandle receives for its oil and gas production. The Company relies heavily on companies with greater resources, staff, equipment, research, and experience for operation of wells and the development and drilling of subsurface prospects. The Company uses its strong financial base and its mineral acreage ownership, coupled with its own geologic and economic evaluation, to participate in drilling operations with these larger companies. This method allows the Company to effectively compete in drilling operations it could not undertake on its own due to financial and personnel limits and allows it to maintain low overhead costs.

(2)

Table of Contents

SOURCES AND AVAILABILITY OF RAW MATERIALS

The existence of commercial oil and gas reserves is essential to the ultimate realization of value from the Company's mineral acreage. These mineral properties and leasehold acreage may be considered a raw material 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 continues to reinvest a portion of its cash flow, after debt service, to the purchase of oil and 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 gas. This participation in exploration and production activities and the purchasing 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 purchases are made from many owners, and the Company does not rely on any particular companies or individuals for these acquisitions.

MAJOR CUSTOMERS

The Company's oil and gas production is sold, in most cases, by the well operators to many different purchasers on a well-by-well basis. During fiscal 2006, sales through two separate operators accounted for approximately 14% and 11%, respectively, of the Company's total revenues. Generally, if one purchaser declines to continue purchasing the Company's oil and natural gas, several other purchasers can be located. Pricing is usually reasonably 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 gas wells stemming from the Company's ownership of mineral acreage generate a portion of the Company's revenues. These royalties are tied to the ownership of the mineral acreage and this ownership is perpetual, unless sold by the Company. Royalties are due and payable to the Company whenever oil and/or gas is produced from wells located on the Company's mineral acreage.

GOVERNMENTAL REGULATION

Oil and 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 and production of oil and gas. These states also have regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties and the regulation of spacing, plugging and abandonment of wells. As previously discussed, the well operators are relied upon by Panhandle to comply with governmental regulations.

Various aspects of the Company's oil and gas operations are regulated by agencies of the federal government. The 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 gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas

Table of Contents

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 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 gas transporters. As a result of the various omnibus rulemaking proceedings in the late 1980's and the individual pipeline restructuring proceedings of the early to mid-1990's, 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) the large-scale divestiture of interstate pipeline-owned 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 available transportation information 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. What new or different regulations FERC and other regulatory agencies may adopt or what effect subsequent regulations may have on production and marketing of natural gas from the Company's properties 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. These regulations may tend to increase the cost of transporting oil by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. These regulations have generally been approved 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

Table of Contents

compliance has been insignificant. The Company does not believe the existence of these environmental laws will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future events. Since the Company does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by the well operators, with Panhandle being responsible for its proportionate share of the costs involved. Panhandle carries liability insurance and, to the extent available at reasonable cost, pollution control coverage. However, all risks are not insured due to the availability and cost of insurance.

EMPLOYEES

At September 30, 2006, Panhandle employed sixteen persons on a full-time basis. Four of the employees are executive officers and the co-presidents are also directors 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.

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

relatively minor changes in the supply of and demand for oil and natural gas;

market uncertainty;

worldwide economic conditions;

weather conditions;

import prices;

political conditions in major oil producing regions, especially the Middle East;

actions taken by OPEC;

competition from alternative sources of energy; and

economic, political and regulatory developments.

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, unusually 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. Quarterly results of operations may fluctuate significantly as a result of, among other things, variations in oil and natural gas prices and production performance. In recent years, oil and natural gas price volatility has become increasingly severe.

A substantial or extended decline in oil and natural gas prices would have a material adverse effect on the Company.

A substantial or extended decline in oil and natural gas prices 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

Table of Contents

extended period would have a 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.

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 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 gas is produced.

All long-lived assets, principally the Company's oil and 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 gas reserves. Any assets held for sale are reviewed for impairment when the Company approves the plan to sell. Because of the uncertainty inherent in these factors, the Company can not 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.

Although the Company's estimated oil and natural gas reserve data is prepared by a consulting engineering firm, estimates may still prove to be inaccurate.

The Company's reserve data represents the estimates of Campbell and Associates, a consulting petroleum engineering firm. Reserve estimates are prepared for all of the Company's properties annually by the reservoir engineer with a limited review mid-year report also prepared. Incorporated into reserve estimates are many factors and assumptions including:

expected reservoir characteristics based on geological, geophysical and engineering assessments;

future production rates based on historical performance and expected future operating and investment activities;

future oil and gas prices; and

future development and operating costs.

Management believes the assumptions are reasonable based on the information available at the time of the estimates. However, actual results could vary considerably which could cause material variances in the estimated quantities of proved oil and natural gas reserves in the aggregate and for a particular geographic location or future net revenues, including production, revenues, taxes and development and operating expenditures. Any significant variation from these assumptions could result in the actual quantity of reserves and future net cash flows being materially different from the estimates. In addition, estimates of reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing oil and natural gas prices, operating and development costs and other factors. Because a complete review of reserve projections is only done at the end of the year, any material change in a reserve estimate is included in subsequent reserve reports.

Table of Contents

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 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 must be done with well operators, as the Company does not operate any of its wells.

Drilling for oil and natural gas may involve 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 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 or may be produced economically.

The ultimate cost of drilling, completing and operating a well is controlled by well operators and cost factors can adversely affect the economics of a project. 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 and the cost and availability of drilling rigs, equipment and services.

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 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 financial reports.

We can not 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 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 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 technology.

Table of Contents

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 and other equipment, as demand for rigs and equipment has 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.

ITEM 2 PROPERTIES

As of September 30, 2006, Panhandle's principal properties consisted of perpetual ownership of 254,778 net mineral acres, held principally in tracts in Oklahoma, New Mexico and Texas and nine other states. The Company also held leases on 20,742 net acres of minerals primarily in Oklahoma. At September 30, 2006, Panhandle held royalty and/or working interests in 4,174 producing oil or gas wells, and 41 wells in the process of being drilled or completed.

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

Panhandle pays ad valorem taxes on its minerals owned in certain states.

Table of Contents**ACREAGE****Mineral Interests**

The following table of mineral interests owned reflects, as of September 30, 2006, 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).

State	Net Acres	Gross Acres	Net Acres Prod g (1)	Gross Acres Prod g (1)	Net Acres Leased (2)	Gross Acres Leased (2)	Net Acres Open (3)	Gross Acres Open (3)
Arkansas	10,048	44,556	1,079	2,936	8,959	41,581	10	39
Colorado	8,326	39,299	109	219	30	200	8,187	38,880
Florida	5,606	12,239					5,606	12,239
Kansas	3,082	11,816	152	1,280			2,930	10,536
Montana	1,007	17,947			11	1,599	996	16,348
North Dakota	11,179	64,286			15	600	11,164	63,686
New Mexico	57,396	174,460	1,352	7,125	320	320	55,724	167,015
Oklahoma	113,078	939,674	32,223	266,110	3,336	24,067	77,519	649,497
South Dakota	1,825	9,300					1,825	9,300
Texas	43,187	361,270	7,060	67,436	1,206	6,777	34,921	287,057
OTHER	44	279					44	279
Total:	254,778	1,675,126	41,975	345,106	13,877	75,144	198,926	1,254,876

(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	Lease Acres Expiring			Net Acres Held by Production
		2007	2008	2009	
Kansas	2,117				2,117
Oklahoma	16,782	914	1,375	548	13,945
Texas	470				470
Other	1,373				1,373
TOTAL	20,742	914	1,375	548	17,905

(9)

Table of Contents**PROVED RESERVES**

The following table summarizes estimates of the proved reserves of oil and gas held by Panhandle. All reserves are located within the United States. Because the Company's non-producing mineral and leasehold interests consist of various small interests in numerous tracts located primarily in Oklahoma, New Mexico and Texas and because the Company is a non-operator and must rely on third parties to propose and drill and operate producing wells, it is not feasible or possible to provide estimates of all proved undeveloped reserves and associated future net revenues. The Company is currently providing proved undeveloped reserve estimates for wells that it has a substantial reason to believe will be drilled in the very near term. In many cases, this means the Company has received some type of notice from the operator that a well will be drilled. All reserve quantity estimates were prepared by Campbell & Associates, Inc., Norman, Oklahoma, a consulting petroleum engineering firm. The Company's reserve estimates are not filed with any other federal agency.

	Barrels of Oil	Mcf of Gas
Proved Developed Reserves		
September 30, 2006	566,110	25,322,756
September 30, 2005	613,536	24,011,062
September 30, 2004	710,513	24,086,120
Proved Undeveloped Reserves		
September 30, 2006	9,081	5,547,083
September 30, 2005	20,787	3,435,341
September 30, 2004	49,729	4,164,633
Total Proved Reserves		
September 30, 2006	575,191	30,869,839
September 30, 2005	634,323	27,446,403
September 30, 2004	760,242	28,250,753

These reserves exclude approximately 1.2 to 1.6 Bcf of CO₂ gas reserves for the years presented.

Because the determination of reserves is a function of testing, evaluating, developing oil and gas reservoirs and establishing a production decline history, along with product price fluctuations, estimates will change as future information concerning individual reservoirs is developed and as market conditions change. Estimated reserve quantities and future net revenues 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. Proved developed reserves are those expected to be recovered through existing well bores under existing economic and operating conditions. Proved undeveloped reserves are reserves that may be recovered from undrilled acreage or units, but are limited to those sites directly offsetting established production units, have sufficient geological data to indicate a reasonable expectation of commercial success and the Company has reason to believe will be drilled in the very near term.

(10)

Table of Contents**ESTIMATED FUTURE NET CASH FLOWS**

Set forth below are estimated future net cash flows with respect to Panhandle's proved reserves (based on the estimated units set forth in the immediately preceding table) for the fiscal 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 have been computed by applying current prices at 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 such reserves. This pricing is based on SEC guidelines. No federal or state income taxes are included in estimated costs. However, the amounts 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 for the periods ended September 30, 2006, 2005, 2004 were as follows: 2006 \$60.50, \$3.49; 2005 \$64.18, \$11.54; 2004 \$44.68, \$5.42. These future net cash flows 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 gas price increases or decreases.

Estimated Future Net Cash Flows (before federal income taxes)

	9-30-06	9-30-05	9-30-04
Proved Developed	\$ 94,939,418	\$ 265,189,328	\$ 129,410,259
Proved Undeveloped	\$ 10,734,504	\$ 31,671,502	\$ 18,782,490
Total Proved	\$ 105,673,922	\$ 296,860,830	\$ 148,192,749

10% Discounted Present Value of Estimated Future Net Cash Flows (before federal income taxes)

	9-30-06	9-30-05	9-30-04
Proved Developed	\$ 62,920,576	\$ 169,417,252	\$ 84,400,194
Proved Undeveloped	\$ 5,716,092	\$ 20,978,021	\$ 12,812,424
Total Proved	\$ 68,636,668	\$ 190,395,273	\$ 97,212,618

The future net cash flows are net of immaterial amounts of future cash flow to be received from CO2 reserves. The large decrease in the natural gas price for 2006 resulted in the decline of future net cash flows in 2006.

OIL AND GAS PRODUCTION

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

	Year Ended 9-30-06	Year Ended 9-30-05	Year Ended 9-30-04
Bbls Oil	97,139	101,581	114,986
Mcf Gas	4,299,142	4,011,226	3,863,277
Mcf	4,881,976	4,620,712	4,553,193

Gas production includes 192,957, 183,743 and 176,605 Mcf of CO2 sold at average prices of \$.65, \$.51 and \$.41 per Mcf for the years ended September 30, 2006, 2005 and 2004, respectively.

Table of Contents**AVERAGE SALES PRICES AND PRODUCTION COSTS**

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

	Year Ended 9-30-06	Year Ended 9-30-05	Year Ended 9-30-04
Average Sales Price			
Per Bbl, Oil	\$ 63.44	\$ 51.30	\$ 35.89
Per Mcf, Gas	\$ 6.94	\$ 6.24	\$ 5.03
Per Mcfe	\$ 7.38	\$ 6.54	\$ 5.18
Average Production (lifting costs) (Per Mcfe of Gas)			
(1)	\$ 0.49	\$ 0.52	\$ 0.48
(2)	\$ 0.59	\$ 0.52	\$ 0.42
	\$ 1.08	\$ 1.04	\$ 0.90

(1) Includes actual well operating costs only.

(2) Includes production taxes, compression, handling and marketing fees paid on natural gas sales and other minor expenses associated with well operations.

Approximately 28% of the Company's oil and gas revenue is generated from small royalty interests in a few thousand wells. These 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 gas wells as of September 30, 2006. Panhandle owns fractional royalty interests or fractional working interests in these wells. The Company does not operate any wells.

	Gross Wells	Net Wells
Oil	955	18.92
Gas	3,219	73.85
TOTAL	4,174	92.77

Information on multiple completions is not available from Panhandle's records, but the number of such is insignificant.

As of September 30, 2006, Panhandle owned 345,106 gross developed mineral acres and 41,975 net developed mineral acres. Panhandle has also leased from others 178,312 gross developed acres, which contain 17,905 net developed acres.

UNDEVELOPED ACREAGE

As of September 30, 2006, Panhandle owned 1,330,020 gross and 212,803 net undeveloped mineral acres, and leases on 30,694 gross and 2,837 net acres.

(12)

Table of Contents**DRILLING ACTIVITY**

The following net productive development and exploratory wells and net dry development and exploratory wells in which the Company had a fractional royalty or working interest were drilled and completed during the fiscal years indicated. Also shown are the net wells purchased during these periods.

	Net Productive Wells	Net Dry Wells
Development Wells		
Fiscal year ended September 30, 2004	4.362204	0.322523
Fiscal year ended September 30, 2005	5.485356	0.142047
Fiscal year ended September 30, 2006	5.477069	0.139168
Exploratory Wells		
Fiscal year ended September 30, 2004	1.245048	0.305172
Fiscal year ended September 30, 2005	0.584992	0.131758
Fiscal year ended September 30, 2006	0.747225	0.159593
Purchased Wells		
Fiscal year ended September 30, 2004	0.009749	0
Fiscal year ended September 30, 2005	1.660737	0
Fiscal year ended September 30, 2006	0	0

PRESENT ACTIVITIES

The following table sets forth the gross and net oil and gas wells drilling or testing as of September 30, 2006, in which Panhandle owns a royalty or working interest. These wells are not yet producing.

	Gross Wells	Net Wells
Oil	2	0.22875
Gas	39	1.19593

Table of Contents

OTHER FACILITIES

The Company leases 9,944 square feet of office space in Oklahoma City, OK. The lease obligation ends in 2009.

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, contain, 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 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 after the date of this report which reflect the occurrence of unanticipated events.

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 2007 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 heavily 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 extremely 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, at times, has increased the volatility associated with these prices.

Table of Contents

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 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 estimated discounted future net cash flows from proved oil and natural gas reserves are determined based on prices 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 required by the SEC for use 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 as of 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, 2006.

Table of Contents**PART II****ITEM 5 MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS**

The Company's Class A Common Stock (Common Stock) is listed on the American Stock Exchange (symbol PHX). The following table sets forth the high and low trade prices of the Common Stock during the periods indicated (all share and per share amounts are adjusted for the 2-for-1 stock split, effective on January 9, 2006):

Quarter Ended	High	Low
December 31, 2004	\$12.65	\$ 8.70
March 31, 2005	\$15.84	\$10.55
June 30, 2005	\$15.25	\$10.53
September 30, 2005	\$22.50	\$13.88
December 31, 2005	\$21.28	\$14.63
March 31, 2006	\$20.33	\$17.48
June 30, 2006	\$22.41	\$16.98
September 30, 2006	\$19.53	\$17.27

As of December 4, 2006, there were 1,877 holders of record of Panhandle's Class A Common Stock.

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 2004	\$ 0.025
March 2005	\$ 0.05
June 2005	\$ 0.025
September 2005	\$ 0.025
December 2005	\$ 0.025
March 2006	\$ 0.08
June 2006	\$ 0.04
September 2006	\$ 0.04

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

Table of Contents**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.

	Year Ended September 30,				
	2006	2005	2004	2003	2002
Revenues					
Oil & Gas Sales	\$ 36,008,527	\$ 30,242,210	\$ 23,578,615	\$ 22,098,198	\$ 13,080,754
Lease Bonuses	410,984	2,214,992	115,938	72,765	41,497
Interest & Other	1,066,169	1,140,973	912,056	285,075	469,146
	\$ 37,485,680	\$ 33,598,175	\$ 24,606,609	\$ 22,456,038	\$ 13,591,397
Costs and Expenses					
Lease Oper. Exp & Prod.					
Taxes	\$ 5,262,834	\$ 4,802,595	\$ 4,098,124	\$ 4,013,572	\$ 3,001,449
Exploration Costs (A)	222,892	784,741	236,939	469,224	417,971
Depr. Depl. Amortization	10,142,367	7,506,571	6,115,500	5,783,457	5,845,779
Provision for Impairment	3,009,953	232,295	841,687	692,220	1,116,234
Loss on Sale of Assets	119,282	291,452			
Gen. & Administrative	3,335,899	4,545,208	3,033,437	2,666,177	2,263,908
Interest Expense	232,234	359,527	488,097	699,266	895,997
	\$ 22,325,461	\$ 18,522,389	\$ 14,813,784	\$ 14,323,916	\$ 13,541,338
Income Before Provision (Benefit) For Income Taxes					
Taxes	\$ 15,160,219	\$ 15,075,786	\$ 9,792,825	\$ 8,132,122	\$ 50,059
Cumulative effect of accounting changes, net of taxes of \$28,500 (B)				46,500	
Provision (Benefit) for Income Taxes	4,586,000	4,591,000	3,063,000	2,217,000	(293,000)
Net Income	\$ 10,574,219	\$ 10,484,786	\$ 6,729,825	\$ 5,961,622	\$ 343,059
Basic Earnings per share	\$ 1.25	\$ 1.25	\$ 0.80	\$ 0.71	\$ 0.04
Diluted Earnings per share	\$ 1.25	\$ 1.24	\$ 0.80	\$ 0.71	\$ 0.04
Dividends Declared per share	\$ 0.185	\$ 0.125	\$ 0.09	\$ 0.07	\$ 0.07
Weighted Average Shares Outstanding (C)					
Basic	8,479,406	8,390,280	8,357,566	8,325,488	8,271,488
Diluted	8,479,406	8,450,238	8,457,602	8,414,852	8,359,888

Net Cash Provided by Operating Activities	\$23,736,931	\$17,154,171	\$15,515,300	\$13,198,368	\$ 7,481,195
Total Assets	\$70,949,242	\$61,241,692	\$54,186,362	\$49,402,534	\$44,837,060
Long-Term Debt	\$ 1,166,649	\$ 3,166,653	\$ 8,516,657	\$12,666,661	\$14,024,000
Shareholders Equity	\$49,065,697	\$38,635,350	\$28,700,515	\$22,527,685	\$16,953,294
		(17)			

Table of Contents

All share and per share amounts are adjusted for the effects of 2-for-1 stock splits, effective in January 2006 and in April 2004.

- (A) The Company uses the successful efforts method of accounting for its oil and gas activities.
- (B) Represents the income effect of the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations* on October 1, 2003. See Note 1: Summary of Significant Accounting Policies of Notes to the Consolidated Financial Statements herein.
- (C) Weighted average shares outstanding for basic and diluted earnings per share are the same in fiscal year 2006 due to the October 2005 amendment to the Deferred Compensation Plan for Non-Employee Directors.

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 the production and sale of oil and natural gas. Results of operations are dependent upon the quantity of production and the price obtained for such production. Prices received by the Company for the sale of its oil and natural gas have fluctuated significantly from period to period. These fluctuations affect the Company's ability to maintain or increase its production from existing oil and gas properties and to explore, develop or acquire new properties. Capital expenditures, which increased significantly in 2006, are expected to again increase in 2007 which should translate into increased production volumes for the Company going forward.

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

	2006	For the Year Ended September 30,		2005	2004
		Percent Incr or (Decr)	Percent Incr or (Decr)		
Production:					
Oil (Bbls)	97,139	(4%)	101,581	(12%)	114,986
Gas (Mcf)	4,299,142	7%	4,011,226	4%	3,863,277
Mcf	4,881,976	6%	4,620,712	1%	4,553,193
Average Sales Price:					
Oil (per Bbl)	\$ 63.44	24%	\$ 51.30	43%	\$ 35.89
Gas (per Mcf)	\$ 6.94	11%	\$ 6.24	24%	\$ 5.03
Mcf	\$ 7.38	13%	\$ 6.54	26%	\$ 5.18

2006 Compared to 2005

Overview

The Company recorded net income of \$10,574,219 in 2006, compared to net income of \$10,484,786 in 2005. Total revenues were higher in 2006 as a result of increased oil and gas sales generated by increases in the average sales prices of oil and natural gas and increased sales volumes of

(18)

Table of Contents

natural gas in 2006 as compared to 2005. The revenue increases were offset by substantial increases in depreciation, depletion and amortization and provision for impairment expense in 2006 as compared to 2005.

Revenues

Total revenues increased \$3,887,505 or 12% for 2006 as compared to 2005. The increase was the result of a \$5,766,317 increase in oil and natural gas sales revenues offset by a decline in lease bonus revenues of \$1,804,008. The increase in oil and gas sales revenues resulted from a 24% and 11% increase in the average sales price for oil and natural gas, respectively, and a 7% increase in gas sales volumes. The decrease in lease bonus revenue in 2006 is a result of the Company leasing all of its non-producing mineral acreage in Arkansas in 2005. The total lease bonus, net of associated basis, was \$1,879,467, as compared to normal leasing activity in 2006. The table above outlines the Company's production and average sales prices for oil and natural gas for 2006 and 2005.

The continuing increase in drilling expenditures and the Company's stated goal of increasing its working interest percentage in new wells drilled is expected to result in continuing increased production volumes for gas in 2007, as compared to 2006. The Company has announced a significant increase, to \$31.5 million, in its drilling budget for 2007. Drilling continues to be concentrated on natural gas prospects and new wells expected to be put on line in 2007 should continue to more than replace the decline of existing well production.

Production by quarter for 2006 was as follows;

First quarter	1,196,923 mcfe
Second quarter	1,173,313 mcfe
Third quarter	1,134,814 mcfe
Fourth quarter	1,376,926 mcfe

Lease Operating Expenses and Production Taxes (LOE)

LOE increased \$175,499 or 6% in 2006. The increase is a result of new larger ownership wells going on line in 2006, as new wells normally have higher operating costs the first several months of production, the continuing increase in the number of wells in which the Company has an interest and general oilfield price increases. In addition water disposal costs on one new well have been disproportionately high. LOE costs per mcfe of production were \$.63 in 2006 as compared to \$.62 in 2005.

Production Taxes:

Production taxes increased \$284,740 or 15% in 2006. The increase is the result of the higher oil and gas revenues in 2006, as production taxes are paid as a percentage of these revenues.

Exploration Costs

Exploration costs decreased \$561,849 in 2006 as compared to 2005. This decrease is principally the result of three higher cost exploratory dry holes drilled in 2005 as compared to only one in 2006. Since the Company utilizes the successful efforts method of accounting for oil and gas operations, only exploratory dry holes result in their costs being charged to exploration costs. Also, the Company's charge to exploration costs for leasehold deemed worthless or the lease term had expired was higher in 2005.

Table of Contents

Depreciation, Depletion and Amortization (DD&A)

DD&A increased \$2,635,796 or 35% in 2006. The increase is a result of higher costs in 2006 on new wells as general oilfield price increases have been substantial the last two years. These higher costs then must be depreciated. In addition, projected remaining production volumes were reduced on some wells, which then increases current DD&A costs. Further, high initial production rates and the inordinate amount of certain wells total estimated reserves being produced rapidly causes DD&A to be heavily weighted to the front end of these wells lives.

Provision for Impairment

The provision for impairment increased \$2,777,658 in 2006 as compared to 2005. The impairment provision in 2005 benefited from higher natural gas prices used in the fair value calculations as compared to substantially lower prices used in the 2006 calculation. Natural gas prices declined dramatically during the fourth fiscal quarter of 2006, and were at a low point for fiscal 2006 at September 30. Market price for natural gas affects the economic evaluation of properties and the potential impairment calculation. The 2006 provision was principally the result of one 27 well field in which the more recent wells drilled were not as good as earlier well results. The last well drilled in the field, which was a large interest well (25%), resulted in a poor well and caused the entire field to be in an impaired status. This field's carrying value was impaired by approximately \$1.9 million. An adjacent one well field also incurred a \$.5 million impairment in 2006.

Loss on Sale of Assets

Loss on sale of assets decreased \$172,170 in 2006 as compared to 2005. Several low performing properties were sold in 2005 at a loss, with one group of wells sold at a loss of approximately \$200,000. In 2006, one property was sold at a loss of \$94,275, and other insignificant sales accounted for the remaining \$25,007.

General and Administrative Costs (G&A)

G&A costs decreased \$1,209,309 or 27% in 2006. The decrease is the result of an amendment to the Directors Deferred Compensation Plan (the Plan). Effective October 19, 2005 the Plan was amended so that on retirement, termination or death of the director or on a change in control of the Company, the shares accrued under the Plan will be issued to the director. This amendment removed the conversion to cash option available under the Plan, which eliminated the requirement to adjust the deferred compensation liability for changes in the market value of the Company's common stock after October 19, 2005. The adjustment of the liability to market value of the shares at the closing price on October 19, 2005 resulted in a credit to G&A of approximately \$288,000 as compared to a charge of approximately \$990,000 in 2005. In addition, the deferred compensation liability after the October 19, 2005 adjustment was reclassified to stockholders' equity.

Interest Expense

Interest expense decreased in 2006 due to lower outstanding debt balances.

Provision for Income Taxes

The 2006 provision for income taxes was basically flat as compared to 2005, as income before provision for income tax increased only \$84,433. The Company utilizes excess percentage depletion to reduce its effective tax rate from the federal statutory rate. The effective tax rate was 30.3% for 2006 and 30.5% for 2005.

Table of Contents**Liquidity and Capital Resources**

At September 30, 2006, the Company had positive working capital of \$4,997,714 as compared to \$3,470,006 at September 30, 2005. The increase is a result of an income tax receivable created by the estimated federal income tax payment made in March 2006 and the directors' deferred compensation liability being reclassified to equity in October 2005. These items were offset by an increase in accounts payable, relating to increased drilling expenditures. Capital expenditures increased and will continue to increase as the Company implements its strategy of increasing the average working interest in new wells drilled, the costs for drilling rigs, field services and equipment continue to increase and the drilling of gas resource wells continues to increase in number.

Cash flow from operating activities increased 38% over last year. Capital expenditures for oil and gas activities for 2006 amounted to \$22,624,040, as compared to \$14,741,637 for 2005. Management currently expects capital expenditures for oil and gas activities to be approximately \$33,000,000 for 2007. This includes expected well drilling and equipment costs of \$31.5 million and \$1.5 for both leasehold acreage purchases and workover expenses on existing wells. The \$31.5 million drilling budget is expected to include expenditures of approximately \$14.5 million on gas resource drilling projects principally in southeast Oklahoma and west Texas, \$12.5 million on drilling projects in western Oklahoma and \$4.5 million in onshore Gulf Coast drilling projects. Any acquisition of oil and gas properties would further increase capital expenditures.

The Company has historically funded capital expenditures, overhead costs and dividend payments from operating cash flow and has utilized, at times, its bank revolving line-of-credit facility to help fund these expenditures. The borrowing base of the current bank line-of-credit can be substantially increased if needed. The \$50 million facility currently has a \$10 million borrowing base which could probably be expanded up to the \$50 million maximum, if needed. The borrowing base is set by the Company to minimize the fee on the unused portion of the borrowing base. Based on expected natural gas production volumes and prices for fiscal 2007, the expected capital expenditure level discussed above, and no meaningful acquisitions of oil and gas properties, borrowings of \$10-15 million in fiscal 2007 are possible. Changes in production volumes or pricing or an acceleration or slowing down of the development in the gas resource projects would materially affect anticipated borrowings.

Contractual Obligations

In October 2006, the Company refinanced its credit facility with BancFirst of Oklahoma City, Oklahoma with a credit facility from Bank of Oklahoma (BOK). The BOK Agreement consists of a term loan in the amount of \$2,500,000 and a revolving loan in the amount of \$50,000,000 which is subject to a semi-annual borrowing base determination. The current borrowing base under the BOK Agreement is \$10,000,000. The term loan matures on September 1, 2007, and the revolving loan matures on October 31, 2009. Monthly payments, beginning December 1, 2006, on the term loan are \$250,000, plus accrued interest. Borrowings under the revolving loan are due at maturity. The term loan bears interest at 30 day LIBOR plus .75%. The revolving loan bears interest at the national prime rate minus from 1.375% to .75%, or 30 day LIBOR plus from 1.375% to 2.0%. The interest rate charged will be based on the percent of the value advanced of the calculated loan value of Panhandle's oil and gas reserves. The interest rate spread from LIBOR or prime increases as a larger percent of the loan value of Panhandle's oil and gas properties is advanced.

Determinations of the borrowing base are made semi-annually or whenever the bank, in its sole discretion, believes there has been a material change in the value of the oil and 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, 2006,

(21)

Table of Contents

the Company was in compliance with the covenants of the BancFirst agreement.

The table below summarizes the Company's contractual obligations, under the BancFirst facility, as of September 30, 2006:

	Total	Payments Due By Period			More than 5 Years
		Less than 1 Year	1-3 Years	3-5 Years	
Contractual Obligations					
Long-term debt obligations	\$3,166,653	\$2,000,004	\$1,166,649	\$	\$

Hedging

Effective January 1, 2007, the Company entered into the following three natural gas collar contracts.

First Contract:

Production volume covered 30,000 mcf/month
 Period covered January through December of 2007
 Prices Floor of \$6.00 and a ceiling of \$9.20

Second Contract:

Production volume covered 40,000 mcf/month
 Period covered January through December of 2007
 Prices Floor of \$6.00 and a ceiling of \$9.20

Third Contract:

Production volume covered 30,000 mcf/month
 Period covered January through December of 2007
 Prices Floor of \$6.00 and a ceiling of \$10.20

2005 Compared to 2004**Overview**

The Company recorded net income of \$10,484,786 in 2005, compared to net income of \$6,729,825 in 2004. Revenues and consequently net income were larger as a result of increased oil and gas sales revenues generated by significant increases in the average sales prices of oil and natural gas in 2005 as compared to 2004. In addition, the Company was able to increase lease bonus revenue by approximately \$2,100,000 in 2005. New leasing activity was the result of an industry wide increase in drilling activity brought on by the increased market price of oil and gas.

Revenues

Total revenues increased 35% to \$33,306,723 in 2005 compared to \$24,606,609 in 2004. The majority of the increase was due to increases in the average sales price for oil and natural gas in 2005 per the above operating data. New production from the Company's drilling activity more than replaced the normal production decline of existing gas wells and the sale in 2005 of approximately 3% (on an annualized basis) of the Company's gas production. These sales of non-core assets were accomplished throughout 2005. Gas production increased 4% for the year in spite of the asset sales. Oil wells beginning production in 2005 could not replace the decline in existing oil production. As the Company is concentrating on the drilling of gas wells, this trend of increasing gas production and decreasing oil production should continue.

Table of Contents

Lease bonus revenue increased \$2,099,054 in 2005, substantially all of which is due to the leasing of all of the Company's non-producing mineral acreage in Arkansas. The total lease bonus, net of associated basis, for the approximate 9,000 Arkansas mineral acres was \$1,879,467.

Lease Operating Expenses and Production Taxes (LOE)

LOE continues to increase each year due to increases in the number of working interest wells in which the Company has an interest, increasing repairs and maintenance needed for existing older wells and normal inflation of costs. Actual well operating costs were \$2,877,972 in 2005 as compared to \$2,592,911 in 2004. Gross production taxes are paid as a percentage of oil and gas sales revenues and therefore increased in 2005 to \$1,924,623, an increase of \$419,410 over 2004.

Exploration Costs

Exploration costs increased \$547,802 or 231% in 2005 as compared to 2004. Since the Company utilizes the successful efforts method of accounting for oil and gas operations, only exploratory dry holes result in their costs being charged to exploration costs. In 2004, there were no high cost exploratory dry holes as compared to three such wells in 2005.

Depreciation, Depletion and Amortization (DD&A)

DD&A increased \$1,391,071 or 23% in 2005 as compared to 2004. Increased DD&A expenses in 2005, as compared to 2004, are a result of rapid decline rates on many wells which have been drilled and gone on production in the last two years coupled with higher costs on these recently completed wells, which then must be depreciated. The high initial production rates result in an inordinate amount of the wells' total estimated reserves being produced rapidly, which then causes the units of production DD&A being heavily weighted to the front end of these wells' lives.

Provision for Impairment

The provision for impairment decreased \$609,392 or 72% in 2005 as compared to 2004. The decrease in impairment charges was principally the result of increased market prices for oil and natural gas. Higher market prices dramatically change the economic evaluation of properties and the calculation of potential impairment.

General and Administrative Costs (G&A)

G&A costs increased \$1,511,771 or 50% in 2005. Personnel related expenses (including salaries, payroll taxes, insurance and ESOP expenses) increased approximately \$250,000 in 2005. Professional fees including; audit, oil and gas land brokers, engineering and Sarbanes-Oxley internal control review assistance increased \$291,000 in 2005 as compared to 2004. G&A expense related to the Non-Employee Directors Deferred Compensation Plan (the Plan) increased approximately \$682,000 in 2005. The increase resulted from the Company recognizing a charge to G&A to adjust the potential shares (approximately 31,000 shares) in the Plan to market price at September 30, 2005. The non-employee directors have elected to defer payment of directors' fees with future payment (in cash or shares) indexed to the Company's stock performance. Subsequent to 2005 fiscal year end, the Company's board of directors voted to amend the Plan to provide future payment only in common stock of the Company. That change will eliminate the requirement to adjust the liability for changes in market price of the Company's common stock for 2006 and future fiscal periods.

Table of Contents

Interest Expense

Interest expense decreased \$128,570 or 26% in 2005 because of lower average outstanding bank debt balances.

Provision for Income Taxes

The provision for income taxes increased in 2005 due to a substantial increase in income before taxes (as discussed above). The Company continued to be able to utilize excess percentage depletion on its oil and gas properties to reduce its tax liability, and its effective tax rate from the federal and state statutory rates. The effective tax rate was approximately 30% in 2005, 31% in 2004 and 27% in 2003.

CRITICAL ACCOUNTING POLICIES

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

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

Oil and Gas Reserves

Of these judgments and estimates, 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 DD&A and impairment calculations. Changes in crude oil and natural gas reserve estimates affect the Company's calculation of depreciation, depletion and amortization, provision for abandonment and assessment of the need for asset impairments. On an annual basis, with a limited scope semi-annual update, the Company's consulting engineer, with assistance from Company geologists, prepares estimates of crude oil and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. As required by the guidelines and definitions established by the SEC, these estimates are based on current crude oil and natural gas pricing. 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 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 in the exploration and production segment.

(24)

Table of Contents

Successful Efforts Method of Accounting

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

Impairment of Assets

All long-lived assets, principally oil and 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 evaluations involve significant judgment since the results are based on estimated future events, such as inflation rates, future sales prices for oil and gas, future production costs, estimates of future oil and gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to oil and gas reserves. 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 can not predict when or if future impairment charges will be recorded.

Oil and Gas Sales Revenue Accrual

The Company does not operate any of its oil and gas properties, and it primarily holds small interests in approximately 4,000 wells. Thus, obtaining timely production data from the well operators is extremely difficult. This requires the Company to utilize past production receipts to estimate its oil and gas sales revenue accrual at the end of each quarterly period. The oil and gas accrual can be impacted by many variables, including initial high production rates of new wells and subsequent rapid decline rates of those wells. This could lead to an over or under accrual of oil and gas sales at the end of any particular quarter. Based on past history, the 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. 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 laws, regulations and interpretations.

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 DISCLOSURE ABOUT MARKET RISK

The Company's results of operations and operating cash flows can be significantly impacted by changes in market prices for oil and gas. Based on the Company's 2006 production, a \$.10 per Mcf change in the price received for natural gas production would result in a corresponding \$430,000 annual change in pre-tax operating cash flow. A \$1.00 per barrel change in the price received for oil production would result in a corresponding \$97,000 annual change in pre-tax operating cash flow. Cash flows could

(25)

Table of Contents

also be impacted, to a lesser extent, by changes in the market interest rates related to the Company's credit facilities. The term loan bears interest at 30 day LIBOR plus .75%. The revolving loan bears interest at the national prime rate minus from 1.375% to .75%, or 30 day LIBOR plus from 1.375% to 2.0%. At September 30, 2006, the Company had \$3,166,653 outstanding under these facilities. A change of .5% in the prime rate or on LIBOR would result in a change to interest expense of \$15,833.

ITEM 8 FINANCIAL STATEMENTS

<u>Management's Report on Internal Control Over Financial Reporting</u>	27
<u>Report of Registered Public Accounting Firm on Internal Control Over Financial Reporting</u>	28
<u>Report of Independent Registered Public Accounting Firm</u>	29
<u>Consolidated Balance Sheets As of September 30, 2006 and 2005</u>	30-31
<u>Consolidated Statements of Income for the Years Ended September 30, 2006, 2005 and 2004</u>	32
<u>Consolidated Statements of Stockholders' Equity for the Years Ended September 30, 2006, 2005 and 2004</u>	33
<u>Consolidated Statements of Cash Flows for the Years Ended September 30, 2006, 2005 and 2004</u>	34-35
<u>Notes to Consolidated Financial Statements</u>	36-50

(26)

Table of Contents

Management's Annual Report on Internal Control Over Financial Reporting

The 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) promulgated 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, 2006. 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, 2006, the Company's internal control over financial reporting was effective based on those criteria.

The Company's independent registered public accounting firm, Ernst & Young, LLP, has audited our assessment of the effectiveness of the Company's internal control over financial reporting as of September 30, 2006, as stated in their report which follows.

(27)

Table of Contents

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

The Board of Directors and Stockholders

Panhandle Royalty Company

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that Panhandle Royalty Company (the Company) maintained effective internal control over financial reporting as of September 30, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO criteria). The Company'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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control 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, management's assessment that the Company maintained effective internal control over financial reporting as of September 30, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2006, 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 the Company as of September 30, 2006 and 2005, and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended September 30, 2006 and our report dated December 6, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma

December 6, 2006

(28)

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Panhandle Royalty Company

We have audited the accompanying consolidated balance sheets of Panhandle Royalty Company (the Company) as of September 30, 2006 and 2005, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2006. 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 Royalty Company at September 30, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2006, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of September 30, 2006, 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 6, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma

December 6, 2006

(29)

Table of ContentsPanhandle Royalty Company
Consolidated Balance Sheets

	September 30,	
	2006	2005
Assets		
Current Assets:		
Cash and cash equivalents	\$ 434,353	\$ 1,638,833
Oil and gas sales receivables	6,471,623	6,641,447
Income tax and other receivables	1,889,636	21,520
Total current assets	8,795,612	8,301,800
Property and equipment at cost, based on successful efforts accounting:		
Producing oil and gas properties	103,129,158	84,388,067
Non-producing oil and gas properties	11,273,373	11,170,926
Furniture and fixtures	562,047	524,721
	114,964,578	96,083,714
Less accumulated depreciation, depletion, and amortization	53,654,385	43,787,403
Net properties and equipment	61,310,193	52,296,311
Investments	596,280	396,424
Other	247,157	247,157
Total assets	\$ 70,949,242	\$ 61,241,692

(Continued on next page)

See accompanying notes.

Table of ContentsPanhandle Royalty Company
Consolidated Balance Sheets

	September 30,	
	2006	2005
Liabilities and Stockholders Equity		
Current Liabilities:		
Accounts payable	\$ 1,564,176	\$ 700,242
Accrued liabilities:		
Deferred compensation		1,335,305
Interest	15,649	23,129
Other	218,069	173,445
Income taxes payable		599,669
Long-term debt due within one year	2,000,004	2,000,004
 Total current liabilities	 3,797,898	 4,831,794
 Long-term debt	 1,166,649	 3,166,653
 Deferred income taxes	 15,498,750	 13,321,750
 Asset retirement obligation and other noncurrent liabilities	 1,420,248	 1,286,145
 Stockholders equity:		
Class A voting common stock, \$.0166 par value; 12,000,000 shares authorized, 8,422,529 issued and outstanding (8,410,886 in 2005)	140,375	140,182
Capital in excess of par value	1,924,587	1,715,206
Deferred directors compensation	1,202,569	
Retained earnings	45,798,166	36,779,962
 Total stockholders equity	 49,065,697	 38,635,350
 Total liabilities and stockholders equity	 \$70,949,242	 \$61,241,692

See accompanying notes.

(31)

Table of Contents

Panhandle Royalty Company
Consolidated Statements of Income

	Year ended September 30,		
	2006	2005	2004
Revenues:			
Oil and gas sales	\$36,008,527	\$30,242,210	\$23,578,615
Lease bonuses and rentals	410,984	2,214,992	115,938
Gain on sales and interest	529,804	745,800	5,436
Income from partnerships	536,365	395,173	906,620
	37,485,680	33,598,175	24,606,609
Costs and expenses:			
Lease operating expenses and production taxes	5,262,834	4,802,595	4,098,124
Exploration costs	222,892	784,741	236,939
Depreciation, depletion, and amortization	10,142,367	7,506,571	6,115,500
Provision for impairment	3,009,953	232,295	841,687
Loss on sale of assets	119,282	291,452	
General and administrative	3,335,899	4,545,208	3,033,437
Interest expense	232,234	359,527	488,097
	22,325,461	18,522,389	14,813,784
Income before provision for income taxes	15,160,219	15,075,786	9,792,825
Provision for income taxes	4,586,000	4,591,000	3,063,000
Net Income	\$10,574,219	\$10,484,786	\$ 6,729,825
Basic earnings per common share:			
Net income	\$ 1.25	\$ 1.25	\$ 0.80
Diluted earnings per common share:			
Net income	\$ 1.25	\$ 1.24	\$ 0.80
<i>See accompanying notes.</i>			

(32)

Table of Contents

Panhandle Royalty Company
Consolidated Statements of Stockholders' Equity

	Common Stock Shares	Common Stock Amount	Capital in Excess of Par Value	Deferred Directors Compensation	Retained Earnings	Total
Balances at September 30, 2003	8,356,404	\$ 139,274	\$ 1,022,249	\$	\$ 21,366,162	\$ 22,527,685
Issuance of common shares to ESOP	20,116	336	172,662			172,998
Issuance of common shares to directors for services	3,046	50	22,109			22,159
Dividends declared (\$.09 per share)					(752,152)	(752,152)
Net Income					6,729,825	6,729,825
Balances at September 30, 2004	8,379,566	\$ 139,660	\$ 1,217,020	\$	\$ 27,343,835	\$ 28,700,515
Issuance of common shares to ESOP	9,186	154	196,380			196,534
Issuance of common shares to directors for services	22,134	368	301,806			302,174
Dividends declared (\$.125 per share)					(1,048,659)	(1,048,659)
Net Income					10,484,786	10,484,786
Balances at September 30, 2005	8,410,886	\$ 140,182	\$ 1,715,206	\$	\$ 36,779,962	\$ 38,635,350
Issuance of common shares to ESOP	11,643	193	209,381			209,574
Increase in deferred directors compensation:						
Reclassification of liability				1,053,408		1,053,408
Charged to expense				149,161		149,161
Dividends declared (\$.185 per share)					(1,556,015)	(1,556,015)
Net Income					10,574,219	10,574,219
	8,422,529	\$ 140,375	\$ 1,924,587	\$ 1,202,569	\$ 45,798,166	\$ 49,065,697

Balances at
September 30, 2006

See accompanying notes.

(33)

Table of Contents

Panhandle Royalty Company
Consolidated Statements of Cash Flows

	Year ended September 30,		
	2006	2005	2004
Operating Activities			
Net income	\$ 10,574,219	\$ 10,484,786	\$ 6,729,825
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization, and impairment	13,152,320	7,738,866	6,957,186
Deferred income taxes	2,177,000	1,072,750	1,920,000
Lease bonus income	(95,892)	(2,133,337)	286,679
Exploration costs	222,892	784,741	236,939
Gain on sale of assets	(415,951)	(365,288)	(6,959)
Equity in earnings of partnerships	(536,365)	(395,173)	(246,573)
Common stock issued to ESOP/Directors Deferred Compensation Plan	149,161	498,708	195,156
Cash provided (used) by changes in assets and liabilities			
Oil and gas sales receivables	169,824	(1,678,455)	(973,115)
Income tax and other receivables	(1,889,363)	218,375	(122,473)
Accounts payable	863,934	(125,699)	273,740
Accrued directors deferred compensation	(281,897)	470,972	344,550
Accrued interest payable	(7,480)	(7,807)	(9,277)
Other accrued liabilities	254,198	(8,937)	60,410
Income taxes payable	(599,669)	599,669	(130,788)
Total adjustments	13,162,712	6,669,385	8,785,475
Net cash provided by operating activities	23,736,931	17,154,171	15,515,300
Investing Activities			
Capital expenditures, including dry hole costs	(22,624,040)	(14,741,637)	(10,946,471)
Proceeds from leasing of fee mineral acreage	493,652	2,304,383	
Distributions received from partnerships	618,509	497,839	369,761
Purchase of investment	(282,000)		
Proceeds from sale of assets	408,487	2,180,397	12,903
Net cash used in investing activities	\$(21,385,392)	\$ (9,759,018)	\$(10,563,807)

(Continued on next page)

See accompanying notes.

Table of Contents

Panhandle Royalty Company
Consolidated Statements of Cash Flows (continued)

	2006	Year ended September 30, 2005	2004
Financing Activities			
Borrowings under debt agreement	\$	\$ 11,350,000	\$ 6,825,000
Payments of loan principal	(2,000,004)	(16,700,004)	(10,975,004)
Payments of dividends	(1,556,015)	(1,048,659)	(752,152)
Purchase and cancellation of common shares			
Net cash used in financing activities	(3,556,019)	(6,398,663)	(4,902,156)
Increase (decrease) in cash and cash equivalents	(1,204,480)	996,490	49,337
Cash and cash equivalents at beginning of year	1,638,833	642,343	593,006
Cash and cash equivalents at end of year	\$ 434,353	\$ 1,638,833	\$ 642,343

**Supplemental Disclosures of Cash Flow
Information**

Interest paid	\$ 219,898	\$ 367,333	\$ 496,441
Income taxes paid, net of refunds received	\$ 4,781,462	\$ 2,668,870	\$ 1,344,321

**Supplemental schedule of noncash investing and
financing activities:**

Reclassification of deferred compensation liability as equity	\$ 1,053,408	\$	\$
Additions and revisions, net, to asset retirement obligations	\$ 141,158	\$ 494,508	\$ 219,675

See accompanying notes.

(35)

Table of Contents

Panhandle Royalty Company
Notes to Consolidated Financial Statements
September 30, 2006, 2005 and 2004

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 gas properties, principally involving the drilling of wells located on the Company's mineral acreage. Panhandle's mineral properties and other oil and gas interests are all located in the United States, primarily in Oklahoma, New Mexico and Texas. The Company is not the operator of any wells. The majority of the Company's oil and gas production is from small interests in several thousand wells located principally in Oklahoma. Approximately 83% of oil and gas revenues are derived from the sale of natural gas. Substantially all the Company's oil and gas production is being 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 gas properties as a normal course of business.

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of Panhandle Royalty Company and its wholly owned subsidiaries after elimination of all material intercompany transactions.

Capitalized costs of certain oil and gas properties and gains and losses on sales of assets for prior years have been reclassified to conform to the current year presentation.

Use of Estimates

The 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 reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Of these judgments and estimates, management considers the estimation of crude oil and natural gas reserves to be the most significant. Changes in crude oil and natural gas reserve estimates affect the Company's calculation of depreciation, depletion and amortization, provision for abandonment and assessment of the need for asset impairments. On an annual basis, with a limited scope semi-annual update, the Company's consulting engineer with assistance from Company geologists prepares estimates of crude oil and natural gas reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. As required by the guidelines and definitions established by the Securities and Exchange Commission, these estimates are based on current crude oil and natural gas pricing. Crude oil and natural gas prices are volatile and largely affected by worldwide consumption and are outside the control of management. Projected future crude oil and natural gas pricing assumptions are used by management to prepare estimates of crude oil and natural gas reserves used in formulating management's overall operating decisions in the exploration and production business.

(36)

Table of Contents

Panhandle Royalty Company

Notes to Consolidated Financial Statements (continued)

1. Summary of Significant Accounting Policies (continued)

The Company does not operate any of its oil and gas properties, and it primarily holds small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult and in most cases substantially delayed. This causes the Company to utilize past production receipts and estimated sales price information to estimate its oil and gas sales revenue accrual at the end of each quarterly period. The oil and gas accrual can be impacted by many variables, including the initial high production rates and possible rapid decline rates of certain new wells and rapidly changing market prices for natural gas. The Company records an accrual to actual adjustment in each succeeding quarter.

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 Gas Sales and Gas Imbalances

The Company sells oil and natural gas to various customers, recognizing revenues as oil and gas is produced and sold. The Company uses the sales method of accounting for 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, 2006 and 2005, the Company had no material gas imbalances.

Charges for gathering and transportation are included in lease operating expenses and production taxes.

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 gas properties. Oil and natural gas sales are generally unsecured. The Company has not experienced any meaningful credit losses in prior years and is not aware of any uncollectible accounts at September 30, 2006 or 2005.

Oil and Gas Producing Activities

The Company follows the successful efforts method of accounting for oil and 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 gas mineral and leasehold costs are capitalized when incurred.

(37)

Table of Contents

Panhandle Royalty Company

Notes to Consolidated Financial Statements (continued)

1. Summary of Significant Accounting Policies (continued)**Derivatives**

The Company had not, through fiscal 2006, entered into derivative instruments to hedge the price risk on its oil or gas production. Beginning in calendar 2007 the Company has entered in costless collar arrangements intended to reduce the Company's exposure to short-term fluctuations in the price of natural gas. Collar contracts set a minimum price, or floor and provide for payments to the Company if the reference price falls below the floor or require payments by the Company if the reference price rises above the ceiling. These arrangements cover only a portion of the Company's production and provide only partial price protection against declines in natural gas prices. These economic hedging arrangements may expose the Company to risk of financial loss and limit the benefit of future increases in prices.

Effective January 1, 2007, the Company entered into the following three natural gas collar contracts.

First Contract:

Production volume covered	30,000 mcf/month
Period covered	January through December of 2007
Prices	Floor of \$6.00 and a ceiling of \$9.20

Second Contract:

Production volume covered	40,000 mcf/month
Period covered	January through December of 2007
Prices	Floor of \$6.00 and a ceiling of \$9.20

Third Contract:

Production volume covered	30,000 mcf/month
Period covered	January through December of 2007
Prices	Floor of \$6.00 and a ceiling of \$10.20

Depreciation, Depletion, Amortization, and Impairment

Depreciation, depletion, and amortization of the costs of producing oil and gas properties are generally computed using the units of production method primarily on a separate property basis using proved reserves as estimated annually by a 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 gas properties include non-producing minerals, which have a net book value of \$5,680,765 at September 30, 2006, consisting of perpetual ownership of mineral interests in several states, with 82% of the acreage in Oklahoma, Texas and New Mexico. As mentioned these mineral rights are perpetual and have been accumulated over the 80 year life of the Company. There are approximately 213,000 acres of non-producing minerals in over 7,000 tracts owned by the Company. An average tract contains 30 acres and the average cost per acre is \$41. Since inception, the Company has continually generated an interest in several thousand oil and 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 over a thirty-three year period on the Company's books. These assets are considered a long-term investment by the Company, they do not expire (as do oil and gas leases), in many cases the same mineral acreage has seen several wells drilled

Table of Contents

Panhandle Royalty Company

Notes to Consolidated Financial Statements (continued)

1. Summary of Significant Accounting Policies (continued)

over the span of several years and development of this acreage has been steady since the 1960 s. Given the above it was concluded that a longer term amortization was appropriate and that 33 years, based on past history and experience was a conservative range. Also, based on the fact that the minerals consist of a large number of properties whose costs are not individually significant, and virtually all are in the Company s core operating areas, the minerals are being amortized on an aggregate basis.

In accordance with the provisions of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, 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 future cash flows. The Company s oil and gas properties were reviewed for indicators of impairment on a field-by-field basis, resulting in the recognition of impairment provisions of \$3,009,953, \$232,295 and \$841,687 respectively, for 2006, 2005 and 2004. The majority of the impairment recognized in 2005 and 2004 relates to fields comprised of a small number of wells or single wells on which the Company does not expect sufficient future net cash flow to recover its carrying cost. The impairment in 2006 is principally the result of a twenty-seven well field in which the more recent wells drilled were not up to earlier well results, and results of the last well drilled, which was a large interest well, were poor resulting in an impairment of the entire field.

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. The cost method is used to account for the Company s investment in one LLC where the Company holds an interest of less than one percent.

Asset Retirement Obligations

The Company owns 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. These expenditures are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). 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, 2006 relating to the Company s retirement obligation for plugging liability:

	Plugging Liability
Plugging Liability as of September 30, 2005	\$ 1,144,299
Accretion of Discount	88,837
Liability Incurred in the Period	141,158
Plugging Liability as of September 30, 2006	\$ 1,374,294

Table of Contents

Panhandle Royalty Company

Notes to Consolidated Financial Statements (continued)

1. Summary of Significant Accounting Policies (continued)**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 these environmental laws will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future events. 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 to the extent available at reasonable cost, 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, 2006 and 2005, there were no such costs accrued.

Earning Per Share of Common Stock

Basic earnings per share (EPS) is calculated using net income divided by the weighted average of common shares outstanding (including unissued, vested directors' shares after October 19, 2005 - see Note 8) during the year. Diluted EPS is similar to basic EPS except that the weighted average common shares outstanding is increased (for periods prior to October 19, 2005) to include the number of additional common shares that would have been outstanding if the dilutive potential common shares had been issued. The treasury stock method is used to calculate dilutive shares, which reduces the gross number of dilutive shares (see Note 6).

Stock-based Compensation

The Company recognizes current compensation costs for its Outside Directors Deferred Compensation Plan (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 closing price of the stock at the date earned. Effective October 19, 2005 the Plan was amended such 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. This amendment removed the conversion to cash option available under the Plan, resulting in reclassification to equity of the liability under the Plan. Effective October 1, 2005, the Company adopted Financial Accounting Standards Board (FASB) No. 123(R) Share Based Payments. Due to the nature of the Company's equity based compensation the adoption of the standard did not have a material effect on the Company's financial statements.

The Company applies SOP 93-6 in accounting for its non-leveraged Employee Stock Ownership Plan. Under SOP 93-6 the Company records as expense, the fair market value of the stock at the time of contribution.

Table of Contents

Panhandle Royalty Company

Notes to Consolidated Financial Statements (continued)

1. Summary of Significant Accounting Policies (continued)

Fair Values of Financial Instruments

The carrying amounts reported in the balance sheets for cash and cash equivalents, receivables, accounts payable, accrued liabilities, and income taxes payable approximate their fair values due to the short maturity of these instruments. The fair value of Company's debt approximates its carrying amount due to the interest rate on the Company's term-loan being a rate which is approximately equivalent to market rates at September 30, 2006 for similar type debt based on the Company's credit worthiness.

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. 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.

New Accounting Pronouncements

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections* a replacement of APB Opinion No. 20 and SFAS No. 3. SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle and a change required by an accounting pronouncement when the pronouncement does not include specific transition provisions. SFAS No. 154 requires retrospective application of changes as if the new accounting principle had always been used. SFAS No. 154 is effective for fiscal years beginning after December 15, 2005, which is our fiscal year beginning October 1, 2006. The adoption of the pronouncement is not expected to have a material impact on the Company's financial position or results of operations.

In June 2006, the FASB issued FIN 48, *Accounting for Uncertainty in Income Taxes* an interpretation of FASB Statement 109, which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006, which will be our fiscal year beginning October 1, 2007. The adoption of this statement is not expected to have a material impact on the Company's financial position or results of operations.

On September 13, 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (SAB 108), which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 is effective for the first fiscal year ending after November 15, 2006, which will be our fiscal year beginning October 1, 2007. The adoption of this statement is not expected to have a material impact on the Company's financial position or results of operations.

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

Table of Contents

Panhandle Royalty Company
Notes to Consolidated Financial Statements (continued)

2. Commitments

The Company leases office space in Oklahoma City, Oklahoma under the terms of an operating lease expiring in April 2009. Future minimum rental payments under the terms of the lease are \$159,108 in 2007, \$159,108 in 2008 and \$92,813 in 2009. Total rent expense incurred by the Company was \$153,164 in 2006, \$158,203 in 2005 and \$115,192 in 2004.

3. Income Taxes

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

	2006	2005	2004
Current:			
Federal	\$2,351,000	\$3,488,250	\$1,113,000
State	58,000	30,000	30,000
	2,409,000	3,518,250	1,143,000
Deferred:			
Federal	1,928,000	1,004,750	1,851,000
State	249,000	68,000	69,000
	2,177,000	1,072,750	1,920,000
	\$4,586,000	\$4,591,000	\$3,063,000

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

	2006	2005	2004
Provision for income taxes at statutory rate	\$5,210,883	\$5,178,799	\$3,329,561
Percentage depletion	(699,384)	(620,982)	(334,365)
State income taxes, net of federal benefit	361,680	63,700	64,350
State net operating loss carryforward benefit	(241,000)		
Other	(46,179)	(30,517)	3,454
	\$4,586,000	\$4,591,000	\$3,063,000

(42)

Table of Contents

Panhandle Royalty Company
Notes to Consolidated Financial Statements (continued)

3. Income Taxes (continued)

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:

	2006	2005
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	\$ 16,538,959	\$ 13,933,416
Deferred tax assets:		
State net operating loss carry forwards	368,890	220,340
Deferred directors compensation and other	671,319	391,326
	1,040,209	611,666
Net deferred tax liabilities	\$ 15,498,750	\$ 13,321,750

4. Long-term Debt

Long-term debt consisted of the following at September 30:

	2006	2005
4.56% loan	\$ 3,166,653	\$ 5,166,657
Current maturities of long-term debt	2,000,004	2,000,004
	\$ 1,166,649	\$ 3,166,653

In October 2006, the Company refinanced its credit facility with BancFirst of Oklahoma City, Oklahoma (Bancfirst) with a new credit facility with Bank of Oklahoma (BOK). The BOK Agreement consists of a term loan in the amount of \$2,500,000 and a revolving loan in the amount of \$50,000,000 which is subject to a semi-annual borrowing base determination. The current borrowing base under the BOK Agreement is \$10,000,000. The term loan matures on September 1, 2007, and the revolving loan matures on October 31, 2009. Monthly payments on the term loan are \$250,000, plus accrued interest. Borrowings under the revolving loan are due at maturity. The term loan bears interest at 30 day LIBOR plus .75%. The revolving loan bears interest at the national prime rate minus from 1.375% to .75%, or 30 day LIBOR plus from 1.375% to 2.0%. The interest rate charged will be based on the percent of the value advanced of the calculated loan value of Panhandle's oil and gas reserves. The interest rate spread from LIBOR or prime increases or decreases as a larger percent of the loan value of Panhandle's oil and gas properties is advanced. 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 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

Table of Contents

Panhandle Royalty Company
Notes to Consolidated Financial Statements (continued)

4. Long-term Debt (continued)

of treasury stock, and require the Company to maintain certain financial ratios. At September 30, 2006, the Company was in compliance with the covenants of the BancFirst agreement.

The amounts of required principal payments under the BancFirst or the BOK agreement for the next five years, as of September 30, 2006, are as follows:

	BancFirst	BOK
2007	\$2,000,004	\$2,500,000
2008	\$1,116,649	\$
2009	\$	\$
2010	\$	\$ 666,653
2011	\$	\$

5. Shareholders Equity

On December 18, 2003, the Company's Board of Directors approved a proposal to amend the Company's Articles of Incorporation to increase the number of authorized shares of Class A Common Stock from 6,000,000 shares to 12,000,000 shares and effect a 2-for-1 stock split of the outstanding Class A Common Stock and a corresponding reduction of the par value per share from \$.03333 to \$.01666. On February 27, 2004, these proposals were put forth to a vote of the shareholders, for which a majority of the shareholders voted in favor of each proposal, causing these proposals to become effective on such date. The Class A Common Stock split was effected in the form of a stock dividend, distributed on April 15, 2004, to stockholders of record on April 1, 2004.

On December 13, 2005, the Company's Board of Directors declared a 2-for-1 stock split of the outstanding Class A Common Stock. The Class A Common Stock split was effected in the form of a stock dividend, distributed on January 9, 2006 to stockholders of record on December 29, 2005.

All agreements concerning Common Stock of the Company, including the Company's Employee Stock Ownership Plan and the Company's commitment under the Deferred Compensation Plan for Non-Employee Directors, provide for the issuance or commitment, respectively, of additional shares of the Company's stock due to the declaration of the stock split. All references to number of shares, per share, and authorized share information in the accompanying consolidated financial statements have been adjusted to reflect the stock split and increase in authorized shares approved on February 27, 2004, at the Annual Meeting of the Stockholders of the Company and to reflect the stock split distributed to stockholders on January 9, 2006.

(44)

Table of Contents

Panhandle Royalty Company
Notes to Consolidated Financial Statements (continued)

6. Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share. The Company's diluted earnings per share calculations in 2005 and 2004 takes into account certain shares that may be issued under the Non-Employee Directors' Deferred Compensation Plan (see Note 8).

	Year ended September 30,		
	2006	2005	2004
Numerator for primary and diluted earnings per share:			
Net income	\$10,574,219	\$10,484,786	\$6,729,825
Denominator:			
For basic earnings per share- weighted average shares (including for 2006, unissued vested directors' shares of 68,488)	8,479,406	8,390,280	8,357,566
Effect of potential diluted shares:			
Directors' deferred compensation shares	*	59,958	100,036
Denominator for diluted earnings per share-adjusted weighted average shares and potential shares	8,479,406	8,450,238	8,457,602

* Not applicable
see Note 8.

The weighted average shares outstanding, potentially dilutive shares, and earnings per share for 2005 and 2004 have been restated to affect the 2-for-1 stock splits discussed in Note 5.

7. Employee Stock Ownership Plan

The Company has an employee stock ownership plan that covers all employees and is established to provide such employees with a retirement benefit. These benefits become fully vested after three years of employment. Contributions to the plan are at the discretion of the Board of Directors and can be made in cash (none in 2006, 2005 or 2004) or the Company's common stock. For contributions of common stock, the Company records as expense, the fair market value of the stock at the time of contribution. The 250,206 shares of the Company's common stock held by the plan as of September 30, 2006, are allocated to individual participant accounts, are included in the weighted average shares outstanding for purposes of earnings per share computations and receive dividends which are credited to the individual accounts. Contributions to the plan consisted of:

Year	Shares	Amount
2006	11,643	\$209,700
2005	9,186	\$196,842
2004	20,116	\$173,125

(45)

Table of Contents

Panhandle Royalty Company

Notes to Consolidated Financial Statements (continued)

8. Deferred Compensation Plan for Directors

Effective November 1, 1994, the Company formed the Panhandle Royalty Company Deferred Compensation Plan for Non-Employee Directors (the Plan). The Plan provides that each eligible director can individually elect to receive shares of Company stock rather than cash for board and committee chair retainers, board meeting fees and board committee meeting fees. These shares are unissued and vest as earned. The shares are credited to each director's deferred fee account at the closing market price of the stock on the date earned. Because the original Plan contained an option allowing the directors to convert the shares to cash upon separation from the Company, the liability was adjusted for subsequent changes in market value of the shares. Upon retirement, termination or death of the director or upon change in control of the Company, the shares accrued under the Plan would have been either issued to the director or converted to cash, at the director's discretion, for the fair market value of the shares on the conversion date, as defined by the Plan. As of September 30, 2006, 70,581 shares (62,412 shares at September 30, 2005) are included in the Plan. Effective October 19, 2005 the Plan was amended such 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. This amendment removed the conversion to cash option available under the Plan, which resulted in reclassification to stockholders' equity of the deferred shares outstanding under the Plan. The deferred balance outstanding at September 30, 2006 under the Plan was \$1,202,569 (\$1,335,305 at September 30, 2005). (\$132,736), \$1,111,097 and \$344,551 was (credited) charged to the Company's results of operations for the years ended September 30, 2006, 2005 and 2004, respectively, and is included in general and administrative expense in the accompanying income statement. The majority (89%) of the \$1,111,097 charged to operations in 2005 was the result of the market prices of the Company's shares increasing from \$17.20 per share at September 30, 2004 to \$42.79 per share at September 30, 2005, thus requiring a charge to expense for the increase per share times the number of shares in the Plan during the year.

9. Information on Oil and Gas Producing Activities

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

During 2006 and 2005 approximately 14% and 17%, respectively, of the Company's total revenues were derived from sales through Chesapeake Operating, Inc. During 2006 sales through JMA Energy Company accounted for approximately 11% of the Company's total revenues. During 2004 sales through Oneok, Inc. accounted for approximately 10% of the Company's total revenues.

(46)

Table of Contents

Panhandle Royalty Company
Notes to Consolidated Financial Statements (continued)

9. Information on Oil and Gas Producing Activities (continued)**Aggregate Capitalized Costs**

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

	2006	2005
Producing properties	\$ 103,129,158	\$ 84,388,067
Non-producing properties	11,273,373	11,170,926
	114,402,531	95,558,993
Accumulated depreciation, depletion and amortization	(53,239,322)	(43,415,988)
Net capitalized costs	\$ 61,163,209	\$ 52,143,005

Costs Incurred

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

	2006	2005 (1)	2004
Property acquisition costs	\$ 983,159	\$ 2,032,823	\$ 612,392
Exploration costs	2,719,068	907,385	1,239,217
Development costs	18,900,917	11,799,545	9,005,341
	\$22,603,144	\$14,739,753	\$10,856,950

(1) Property acquisition costs include \$900,000 related to the acquisition of proved properties.

10. Supplementary Information on Oil and 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 Securities and Exchange Commission (SEC) and SFAS No. 69, *Disclosures About Oil and Gas Producing Activities*.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Because the Company's non-producing mineral and leasehold interests consist of various small interests in numerous tracts located primarily in Oklahoma, New Mexico, and Texas, it is not economically feasible for the Company to provide estimates of all proved undeveloped reserves.

(47)

Table of Contents

Panhandle Royalty Company

Notes to Consolidated Financial Statements (continued)

10. Supplementary Information on Oil and Gas Reserves (Unaudited) (continued)

The Company's net proved (including certain undeveloped reserves described above) oil and gas reserves, all of which are located in the United States, as of September 30, 2006, 2005 and 2004, have been estimated by Campbell & Associates, Inc., a consulting petroleum engineering firm. 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, 2006, 2005 and 2004. 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 Quantities of Proved Oil and Gas Reserves

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

	Proved Reserves	
	Oil	Gas
	(Mbarrels)	(MMcf)
September 30, 2003	836	28,270
Revisions of previous estimates	(50)	(2,489)
Extensions and discoveries	89	6,333
Production	(115)	(3,863)
September 30, 2004	760	28,251
Revisions of previous estimates	(60)	(3,122)
Acquisitions	4	409
Divestitures	(60)	(814)
Extensions and discoveries	92	6,733
Production	(102)	(4,011)
September 30, 2005	634	27,446
Revisions of previous estimates	(11)	(3,557) (1)
Extensions and discoveries	49	11,279
Production	(97)	(4,299)
September 30, 2006	575	30,869

(1) The prices used to calculate reserves and future cash flows from reserves for oil and natural gas, respectively, were as follows:
September 30,

2006 \$60.50,
\$3.49; 2005
\$64.18, \$11.54.

The large
decrease in the
natural gas price
for 2006
resulted in a
negative
revision to gas
reserves of
4,365 mmcf,
meaning other
revisions were a
positive 808
mmcf.

(48)

Table of Contents

Panhandle Royalty Company
Notes to Consolidated Financial Statements (continued)

10. Supplementary Information on Oil and Gas Reserves (Unaudited) (continued)

	Proved Developed Reserves		Proved Undeveloped Reserves	
	Oil (Mbarrels)	Gas (MMcf)	Oil (Mbarrels)	Gas (MMcf)
September 30, 2003	703	23,600	133	4,670
September 30, 2004	710	24,086	50	4,165
September 30, 2005	613	24,011	21	3,435
September 30, 2006	566	25,323	9	5,547

The above reserve numbers exclude approximately 1.2 – 1.6 Bcf of CO₂ gas reserved for the years ended September 30, 2006, 2005, 2004 and 2003.

Standardized Measure of Discounted Future Net Cash Flows

Estimates of future cash flows from proved oil and gas reserves, based on current prices and costs, as of September 30 are shown in the following table. Estimated income taxes are calculated by applying the appropriate year-end tax rates to the estimated future pretax net cash flows less depreciation of the tax basis of properties and statutory depletion allowances. Prices used for determining future cash flows from oil and natural gas for the periods ended September 30, 2006, 2005, 2004 were as follows: 2006 \$60.50, \$3.49; 2005 \$64.18, \$11.54; 2004 \$44.68, \$5.42.

	2006	2005	2004
Future cash inflows	\$ 146,872,790	\$ 358,380,000	\$ 187,769,949
Future production costs	34,045,630	55,406,990	35,447,026
Future development costs	7,101,523	5,458,591	3,716,299
Asset retirement obligation	1,374,294	1,144,299	728,037
Future net cash inflows before future income tax expenses	104,351,343	296,370,120	147,878,587
Future income tax expense	24,394,272	84,708,027	40,959,776
Future net cash flows	79,957,071	211,662,093	106,918,811
10% annual discount	28,765,504	78,040,774	37,768,822
Standardized measure of discounted future net cash flows	\$ 51,191,567	\$ 133,621,319	\$ 69,149,989

(49)

Table of Contents

Panhandle Royalty Company

Notes to Consolidated Financial Statements (continued)

10. Supplementary Information on Oil and Gas Reserves (Unaudited) (continued)

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

	2006	2005	2004
Beginning of year	\$ 133,621,319	\$ 69,149,989	\$ 53,740,536
Changes resulting from:			
Sales of oil and gas, net of production costs	(30,745,693)	(25,439,615)	(19,480,491)
Net change in sales prices and production costs	(123,034,702)	96,847,355	23,317,917
Net change in future development costs	(1,053,612)	(1,142,715)	91,349
Net change in asset retirement obligation	(149,267)	(266,949)	(144,078)
Extensions and discoveries	23,822,148	43,200,477	20,153,689
Revisions of quantity estimates	(7,891,218)	(19,409,623)	(8,026,019)
Divestitures of reserves-in-place		(6,975,566)	
Acquisition of reserves-in-place		2,585,268	
Accretion of discount	19,006,216	9,698,899	7,516,647
Net change in income taxes	39,908,385	(28,601,833)	(6,413,806)
Change in timing and other, net	(2,292,009)	(6,024,368)	(1,605,755)
Net change	(82,429,752)	64,471,330	15,409,453
End of year	\$ 51,191,567	\$ 133,621,319	\$ 69,149,989

11. Quarterly Results of Operations (Unaudited)

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

	Fiscal 2006			September 30
	Quarter Ended			
	December 31	March 31	June 30	
Revenues	\$ 12,207,679	\$ 8,728,506	\$ 7,414,606	\$ 9,134,889
Income before provision for income taxes	7,471,118	3,842,760	2,815,878	1,030,463
Net income	4,894,118	2,653,760	2,078,878	947,463
Basic earnings per share	\$ 0.58	\$ 0.31	\$ 0.25	\$ 0.11
Diluted earnings per share	\$ 0.58	\$ 0.31	\$ 0.25	\$ 0.11

	Fiscal 2005			September 30
	Quarter Ended			
	December 31	March 31	June 30	
Revenues	\$ 8,492,360	\$ 6,274,779	\$ 9,215,046	\$ 9,324,538
Income before provision for income taxes	3,616,344	2,210,649	5,056,419	4,192,374
Net income	2,448,344	1,575,649	3,419,419	3,041,374
Basic earnings per share	\$ 0.29	\$ 0.19	\$ 0.41	\$ 0.36
Diluted earnings per share	\$ 0.29	\$ 0.19	\$ 0.40	\$ 0.36

(50)

Table of Contents**ITEM CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND
9 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 Securities Exchange Act of 1934, 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 Co-President/COO and Co-President/CFO (Co-Presidents), 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 Co-Presidents have concluded that, subject to the limitations noted above, the Company's disclosure controls and procedures were effective to ensure that material information relating to the Company, including its consolidated subsidiary, is made known to them.

(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 Co-Presidents, 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, 2006.

The Company management's assessment of the effectiveness of its internal controls over financial reporting as of September 30, 2006 has been audited by Ernst and Young, LLP, an independent registered public accounting firm, as stated in their report which is included in this report.

(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 or subsequent to the date the assessment was completed.

(51)

Table of Contents

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 and to Form 10-QSB dated March 31, 1999).

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)
- (4) Instruments defining the rights of security holders (incorporated by reference to Certificate of Incorporation and By-Laws listed above)
- (10) Amendment to Loan Agreement (incorporated by reference to Form 10-K dated September 30, 2003)
- (10) Agreement indemnifying directors and officers (incorporated by reference to Form 10-K dated September 30, 1989)
- (21) Subsidiaries of the Registrant
- (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

REPORTS ON FORM 8-K

No Form 8-K's were filed in the fourth quarter of fiscal 2006.

(52)

Table of Contents

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 ROYALTY COMPANY

By: /s/ Michael C. Coffman

By: /s/ Ben D. Hare

Michael C. Coffman
Co-President;
Chief Financial Officer

Ben D. Hare
Co-President;
Chief Operating Officer

Date: December 12, 2006

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/ E. Chris Kauffman

/s/ Bruce M. Bell

E. Chris Kauffman, Chairman of Board

Bruce M. Bell, Director

Date December 12, 2006

Date December 12, 2006

/s/ Robert A. Reece

/s/ Robert E. Robotti

Robert A. Reece, Director

Robert E. Robotti, Director

Date December 12, 2006

Date December 12, 2006

/s/ H. Grant Swartzwelder

/s/ Robert O. Lorenz

H. Grant Swartzwelder, Director

Robert O. Lorenz, Director

Date December 12, 2006

Date December 12, 2006

/s/ Lonnie J. Lowry

Lonnie J. Lowry, Vice President,
Controller and Secretary (Chief
Accounting Officer)

Date December 12, 2006