MEXCO ENERGY CORP
Form 10-K
June 23, 2008

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

FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended March 31, 2008

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File No. 0-6694

MEXCO ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Colorado	**84-0627918**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
214 W. Texas Avenue, Suite 1101 **Midland, Texas** (Address of principal executive offices)	**79701** (Zip Code)

Registrant's telephone number, including area code: **(432) 682-1119**

Securities registered pursuant to Section 12(b) of the Act: **None**

Securities registered pursuant to Section 12(g) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, $0.50 par value	**American Stock Exchange**

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

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 o No þ

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 twelve (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 ninety (90) days. Yes þ No o

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 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. o

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

Large Accelerated Filer o	Accelerated Filer o	Non-Accelerated Filer þ (Do not check if a smaller reporting company)	Smaller Reporting Company o

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

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of September 30, 2007 (the last business day of the Registrant's most recently completed second quarter) was $2,868,488 based on Mexco Energy Corporation's closing common stock price of $5.15 per share on that date as reported by the American Stock Exchange.

There were 1,757,366 shares of the registrant's common stock, $.50 par value, outstanding as of June 19, 2008.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement relating to the 2008 Annual Meeting of Shareholders to be held on September 11, 2008, have been incorporated by reference in Part III of this Form 10-K. Such Proxy Statement will be filed with the Commission not later than July 18, 2008.

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PART IV

This Annual Report on Form 10-K contains forward-looking statements that are based on management's current expectations. Forward-looking statements include statements regarding our plans, beliefs or current expectations and may be signified by the words "could", "should", "expect", "project", "estimate", "believe", "ant "intend", "budget", "plan", "forecast", "predict" and other similar expressions. Forward-looking statements app throughout this Form 10-K with respect to, among other things: profitability; planned capital expenditures; estimates of oil and gas production; future project dates; estimates of future oil and gas prices; estimates of oil and gas reserves; our future financial condition or results of operations; and our business strategy and other plans and objectives for future operations. Actual results in future periods may differ materially from those expressed or implied by such forward-looking statements because of a number of risks and uncertainties affecting our business, including those discussed in "Item 1 – Business – Risk Factors" and elsewhere in this report. We disclaim any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Unless the context otherwise requires, references to "the Company", "Mexco", "we", "us" or "our" mean Mexco Ene Corporation and its consolidated subsidiaries.

Definitions of terms commonly used in the oil and gas industry and in this Form 10-K can be found in the "Glossary of Abbreviations and Terms".

PART I

ITEM 1. BUSINESS

General

Mexco Energy Corporation, a Colorado corporation, is an independent oil and gas company engaged in the acquisition, exploration and development of oil and gas properties located in the United States. Incorporated in April 1972 under the name Miller Oil Company, the Company changed its name to Mexco Energy Corporation effective April 30, 1980. At that time, the shareholders of the Company also approved amendments to the Articles of Incorporation resulting in a one-for-fifty reverse stock split of the Company's common stock.

On February 25, 1997, Mexco Energy Corporation acquired all of the issued and outstanding stock of Forman Energy Corporation, a New York corporation also engaged in oil and gas exploration and development.

In April 2004, Mexco Energy Corporation formed OBTX, LLC, a Delaware limited liability company. OBTX, LLC owned 50% of GazTex, LLC, a limited liability company which was dissolved in May 2008. Since its date of formation, OBTX, LLC has been included in the consolidated financial statements. Prior to dissolution GazTex, LLC had no operations other than evaluation activities on properties in Russia.

Our total estimated proved reserves at March 31, 2008 were approximately 7.857 Bcf of natural gas and 217,000 barrels of oil and natural gas liquids, and our estimated present value of proved reserves was approximately $41 million based on estimated future net revenues discounted at 10% per annum, pricing and other assumptions set forth in "Item 2 – Properties" below. During fiscal 2008, we added proved reserves of 794,000 mcfe through extensions and discoveries, added 584,000 mcfe through acquisitions and had upward revisions of previous estimates of 43,000 mcfe.

Nicholas C. Taylor beneficially owns approximately 50% of the outstanding shares of our common stock. Mr. Taylor is also our President and Chief Executive Officer. As a result, Mr. Taylor has significant influence in matters voted on by our shareholders, including the election of our Board members. Mr. Taylor participates in all facets of our business and has a significant impact on both our business strategy and daily operations.

Company Profile

Since our inception, we have been engaged in acquiring and developing oil and gas properties and the exploration for and production of oil and gas within the United States. We primarily focus on the exploration for and development of natural gas reserves, as well as increased profit margins through reductions in operating costs. Our long-term strategy is to increase shareholder value by increasing oil and natural gas reserves, production and revenues. In addition to exploration, we are also engaged in the business of acquiring proved reserves that fit well within existing operations or in areas where the Company is establishing new operations. Preferred properties have most of their value in producing wells, behind pipe reserves or high quality proved undeveloped locations. Competition for the purchase of proved reserves is intense. Sellers often utilize a bid process to sell properties. This process usually intensifies the competition and makes it extremely difficult for us to acquire reserves without assuming significant price and production risks. We are actively searching for opportunities to acquire proved oil and gas properties; however, because the competition is intense, we cannot give any assurance that we will be successful in our efforts during fiscal 2009.

While we own oil and gas properties in other states, the majority of our activities are centered in West Texas. We acquire interests in producing and non-producing oil and gas leases from landowners and leaseholders in areas considered favorable for oil and gas exploration, development and production. In addition, we may acquire oil and gas interests by joining in oil and gas drilling prospects generated by third parties. We may also employ a combination of the above methods of obtaining producing acreage and prospects. In recent years, we have placed primary emphasis on the evaluation and purchase of producing oil and gas properties, both working and royalty interests, and prospects that could have a potentially meaningful impact on our reserves.

Oil and Gas Operations

As of March 31, 2008, gas reserves constituted approximately 86% of our total proved reserves and approximately 65% of our revenues for fiscal 2008. Revenues from oil and gas royalty interests accounted for approximately 29% of our revenues for fiscal 2008.

Viejos Gas Field properties, encompassing 2,583 gross acres, 156 net acres, 18 gross wells and 1.27 net wells in Pecos County, Texas, account for approximately 2% of our discounted future net cash flows from proved reserves as of March 31, 2008, and for fiscal 2008, approximately 6% of revenues and 7% of production costs.

Gomez Gas Field properties, encompassing 13,847 gross acres, 73 net acres, 24 gross wells and .11 net wells in Pecos County, Texas, account for approximately 6% of our discounted future net cash flows from proved reserves as of March 31, 2008, and for fiscal 2008, approximately 9% of revenues and 4% of production costs. All of these properties, except for one, are royalties.

El Cinco Gas Field properties, encompassing 1,006 gross acres, 766 net acres, 7 gross producing wells and 5.325 net wells in Pecos County, Texas, account for approximately 45% of our discounted future net cash flows from proved reserves as of March 31, 2008. This is a multi-pay area where most of the leases have potential reserves in two zones. Of this amount approximately 26% of our discounted future net cash flows from proved reserves are attributable to proven undeveloped reserves which will be developed through re-entry of existing wells and new drilling. For fiscal 2008, these properties accounted for approximately 19% of revenues and 43% of production costs.

Newark East (Barnett Shale) Gas Field properties, encompassing 5116 gross acres, 54 net acres, 84 gross producing wells and .44 net wells in Denton and Tarrant Counties, Texas, account for approximately 6% of our discounted future net cash flows from proved reserves as of March 31, 2008, and for fiscal 2008, approximately 8% of revenues and 1% of production costs. These costs are ad valorem and production taxes. All of these properties are royalties including a purchase of $1,850,000 on December 31, 2007, which has materially increased our earnings. Subsequently on June 6, 2008 we purchased additional Barnett Shale royalties in the Newark East Gas Field at a purchase price of $429,000.

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We acted as operator of an exploratory well drilled to a depth of approximately 6,680 feet in the Cherry Canyon producing interval in Loving County, TX. As of March 31, 2008 and based on information available at that time, the calculated reserves for our 31.25% working interest (22.94% net revenue interest) in this well accounted for 8% of our discounted future net cash flows from proved reserves. This well, based on a four point test by an independent testing firm, was calculated to produce at an absolute open flow rate of 12,773,000 cubic feet of natural gas per day. During this four hour test the well actually produced 1,366,000 cubic feet of natural gas, 26 barrels of 63 gravity condensate and 12 barrels of water on chokes ranging from 11/64 to 15/64 inches. Previously the well had been shut in for a period in excess of 72 hours. The rates at which this will be produced and sold have not yet been determined and may be substantially different from these potential tests, based on regulatory and engineering considerations as well as performance of the well over longer periods of time. We anticipate future development on this acreage.

We own interests in and operate 17 producing wells, one shut-in well and one salt water disposal well. We own partial interests in an additional 2,189 producing wells located in the states of Texas, New Mexico, Oklahoma, Louisiana, Arkansas, Wyoming, Kansas, Colorado, Montana and North Dakota. Additional information concerning these properties and our oil and gas reserves is provided below.

The following table indicates our oil and gas production in each of the last five years, all of which is located within the United States:

Year	Oil(Bbls)	Gas (Mcf)
2008	17,504	379,048
2007	16,738	339,174
2006	17,118	370,069
2005	17,372	404,133
2004	20,279	487,564

Competition and Markets

The oil and gas industry is a highly competitive business. Competition for oil and gas reserve acquisitions is significant. We may compete with major oil and gas companies, other independent oil and gas companies and individual producers and operators, some of which have financial and personnel resources substantially in excess of those available to us. As a result, we may be placed at a competitive disadvantage. Competitive factors include price, contract terms and types and quality of service, including pipeline distribution. The price for oil and gas is widely followed and is generally subject to worldwide market factors. Our ability to acquire and develop additional properties in the future will depend upon our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment in a timely manner.

In addition, the oil and gas industry as a whole also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. The price and availability of alternative energy sources could adversely affect our revenue.

Market factors affect the quantities of oil and natural gas production and the price we can obtain for the production from our oil and natural gas properties. Such factors include: the extent of domestic production; the level of imports of foreign oil and natural gas; the general level of market demand on a regional, national and worldwide basis; domestic and foreign economic conditions that determine levels of industrial production; political events in foreign oil-producing regions; and variations in governmental regulations including environmental, energy conservation and tax laws or the imposition of new regulatory requirements upon the oil and natural gas industry.

The market for our oil, gas and natural gas liquids production depends on factors beyond our control including: domestic and foreign political conditions; the overall level of supply of and demand for oil, gas and natural gas liquids; the price of imports of oil and gas; weather conditions; the price and availability of alternative fuels; the proximity and capacity of gas pipelines and other transportation facilities; and overall economic conditions.

Major Customers

We had sales to the following company(s) that amounted to 10% or more of revenues for the year ended March 31:

	2008	2007	2006
Chesapeake Operating	14%	—	—
Conoco Phillips	13%	—	—
Southern Union Gas Services	—	12%	16%

Because a ready market exists for oil and gas production, we do not believe the loss of any individual customer would have a material adverse effect on our financial position or results of operations.

Regulation

Our exploration, development, production and marketing operations are subject to extensive rules and regulations by federal, state and local authorities. Numerous federal, state and local departments and agencies have issued rules and regulations binding on the oil and gas industry, some of which carry substantial penalties for noncompliance. State statutes and regulations require permits for drilling operations, bonds and reports concerning operations. Most states also have statutes and regulations governing conservation and safety matters, including the unitization and pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells and the spacing of such wells. Such statutes and regulations may limit the rate at which oil and gas otherwise could be produced from our properties. These statutes, along with the regulations interpreting the statutes, generally are intended to prevent waste of oil and natural gas, and to protect correlative rights to produce oil and natural gas by assigning allowable rates of production to each well or proration unit. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. Because these rules and regulations are frequently amended or reinterpreted, we are not able to predict the future cost or impact of complying with such laws.

The Federal Energy Regulatory Commission (“FERC”) regulates interstate natural gas transportation rates and service conditions, which affect the marketing of gas we produce, as well as the revenues we receive for sales of such production. Since the mid-1980s, the FERC has issued various orders that have significantly altered the marketing and transportation of gas. These orders resulted in a fundamental restructuring of interstate pipeline sales and transportation services, including the unbundling by interstate pipelines of the sales, transportation, storage and other components of the city-gate sales services such pipelines previously performed. These FERC actions were designed to increase competition within all phases of the gas industry. The interstate regulatory framework may enhance our ability to market and transport our gas, although it may also subject us to greater competition and to the more restrictive pipeline imbalance tolerances and greater associated penalties for violation of such tolerances.

Our sales of oil and natural gas liquids are not presently regulated and are made at market prices. The price we receive from the sale of those products is affected by the cost of transporting the products to market. The FERC has implemented regulations establishing an indexing system for transportation rates for oil pipelines, which, generally, would index such rate to inflation, subject to certain conditions and limitations. We are not able to predict with any certainty what effect, if any, these regulations will have on us. Other factors being equal, the regulations may, over time, tend to increase transportation costs which may have the effect of reducing wellhead prices for oil and natural gas liquids.

Environmental Matters

By nature of our oil and gas operations, we are subject to extensive federal, state and local environmental laws and regulations controlling the generation, use, storage and discharge of materials into the environment or otherwise relating to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or production commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within protected areas, restrict the rate of oil and gas production, require remedial actions to prevent pollution from former operations and impose substantial liabilities for pollution resulting from our operations. In addition, these laws and regulations may impose substantial liabilities and penalties for failure to comply with them or for any contamination resulting from our operations. We believe we are in compliance, in all material respects, with applicable environmental requirements. We do not believe costs relating to these laws and regulations have had a material adverse effect on our operations or financial condition in the past. Public interest in the protection of the environment has increased dramatically in recent years. The trend of applying more expansive and stricter environmental legislation and regulations to the natural gas and oil industry could continue, resulting in increased costs of doing business and consequently affecting our profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

The United States Oil Pollution Act of 1990 (“OPA ‘90”), and similar legislation enacted in Texas, Louisiana and other coastal states, addresses oil spill prevention and control and significantly expands liability exposure across all segments of the oil and gas industry. OPA ‘90 and such similar legislation and related regulations impose on us a variety of obligations related to the prevention of oil spills and liability for damages resulting from such spills. OPA ‘90 imposes strict and, with limited exceptions, joint and several liabilities upon each responsible party for oil removal costs and a variety of public and private damages.

The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the “Superfund” law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We do not believe that we will be required to incur any material capital expenditures to comply with existing environmental requirements.

Our operations may be subject to the Clean Air Act (“CAA”) and comparable state and local requirements. In 1990 Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed and continue to develop regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

The Resource Conservation and Recovery Act ("RCRA") and analogous state laws govern the handling and disposal of hazardous and solid wastes. Wastes that are classified as hazardous under RCRA are subject to stringent handling, recordkeeping, disposal and reporting requirements. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, many ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, are regulated as hazardous wastes. Although the costs of managing hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies.

State water discharge regulations and federal waste discharge permitting requirements adopted pursuant to the Federal Water Pollution Control Act ("Clean Water Act") prohibit, or are expected in the future to prohibit, the discharge of produced water and sand and other substances related to the oil and gas industry into coastal waters. Although the costs to comply with such mandates under state or federal law may be significant, the entire industry will experience similar costs, and we do not believe that these costs will have a material adverse impact on our financial condition and operations.

Title to Properties

As is customary in the oil and gas industry, only a preliminary title examination is conducted at the time properties believed to be suitable for drilling operations are acquired by us. Prior to the commencement of drilling operations, a thorough title examination of the drill site tract is conducted and curative work is performed with respect to significant defects, if any, before proceeding with operations. A thorough title examination has been performed with respect to substantially all leasehold producing properties currently owned by us. We believe the title to our leasehold properties is good and defensible in accordance with standards generally acceptable in the oil and gas industry subject to such exceptions that, in the opinion of counsel employed in the various areas in which we have conducted exploration activities, are not so material as to detract substantially from the use of such properties.

The leasehold properties we own are subject to royalty, overriding royalty and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements and current taxes, development obligations under oil and gas leases and other encumbrances, easements and restrictions. We do not believe any of these burdens will materially interfere with the use of these properties.

Substantially all of our properties are currently mortgaged under a deed of trust to secure funding through a revolving line of credit.

Insurance

Our operations are subject to all the risks inherent in the exploration for, and development and production of oil and gas including blowouts, fires and other casualties. We maintain insurance coverage customary for operations of a similar nature, but losses could arise from uninsured risks or in amounts in excess of existing insurance coverage.

Executive Officers

The following table sets forth certain information concerning the executive officers of the Company as of March 31, 2008.

Name	Age	Position
Nicholas C. Taylor	70	President and Chief Executive Officer
Donna Gail Yanko	63	Vice President and Secretary
Tamala L. McComic	39	Vice President, Treasurer, Assistant Secretary and Chief Financial Officer

Set forth below is a description of the principal occupations during at least the past five years of each executive officer of the Company.

Nicholas C. Taylor was elected Chief Executive Officer, President, Treasurer and Director of the Company in April 1983 and continues to serve as Chief Executive Officer, President and Director on a part time basis, as required. Mr. Taylor served as Treasurer until March 1999. From July 1993 to the present, Mr. Taylor has been involved in the independent practice of law and other business activities. For more than the prior 19 years, he was a director and shareholder of the law firm of Stubbeman, McRae, Sealy, Laughlin & Browder, Inc., Midland, Texas, and a partner of the predecessor firm. In 1995 he was appointed by the Governor of Texas to the State Securities Board through January 2001. In addition to serving as chairman for four years, he continued to serve as a member until 2004. In November 2005 he was appointed by the Speaker of the House to the Texas Ethics Commission for a term of five years.

Donna Gail Yanko worked as a part-time administrative assistant to the Chief Executive Officer and as Assistant Secretary of the Company until June 1992 when she was appointed Secretary. Mrs. Yanko was appointed to the position of Vice President and elected to the board of directors of the Company in 1990.

Tamala L. McComic, a Certified Public Accountant, became Controller for the Company in July 2001. She was appointed Assistant Secretary of the Company in August 2001 and Treasurer in September 2001. In May 2003, Mrs. McComic was appointed Chief Financial Officer and Vice President and continues to serve as Treasurer and Assistant Secretary.

Employees

As of March 31, 2008, we had two full-time and four part-time employees. We believe that relations with these employees are generally satisfactory. Our employees are not covered by collective bargaining arrangements. From time to time, we utilize the services of independent contractors to perform various field and other services. Experienced personnel are available in all disciplines should the need to hire additional staff arise.

Office Facilities

We maintain our principal offices at 214 W. Texas, Suite 1101, Midland, Texas pursuant to a month to month lease.

Access to Company Reports

Mexco Energy Corporation files quarterly, yearly and other reports with the Security Exchange Commission ("SEC"). You may obtain a copy of any materials filed by Mexco with the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549, by calling 1-800-SEC-0330 or visiting their website at http://www.sec.gov which contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC. Mexco also employs the Public Register's Annual Report Service which can provide you a copy of our annual report at http://www.prars.com, free of charge, as soon as practicable after providing such report to the SEC. We also currently maintain an internet website at http://www.mexcoenergy.com. Our website contains our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Additionally, our Code of Business Conduct and Ethics and the charters of our Audit Committee, Compensation Committee and Nominating Committee are posted on our website. Any of these corporate documents as well as any of the SEC filed reports are available in print free of charge to any stockholder who requests them. Requests should be directed to our corporate assistant secretary by mail to P.O. Box 10502, Midland, Texas 79702 or by email to mexco@sbcglobal.net.

ITEM 1A. RISK FACTORS

There are many factors that affect our business and results of operations, some of which are beyond our control. The following is a description of some of the important factors that may cause results of operations in future periods to differ materially from those currently expected or desired.

Volatility of oil and gas prices significantly affects our results and profitability.

Prices for oil and natural gas fluctuate widely. We cannot predict future oil and natural gas prices with any certainty. Historically, the markets for oil and gas have been volatile, and they are likely to continue to be volatile. Factors that can cause price fluctuations include the level of global demand for petroleum products, foreign supply of oil and gas, the establishment of and compliance with production quotas by oil-exporting countries, weather conditions, the price and availability of alternative fuels and overall political and economic conditions in oil producing countries.

Increases and decreases in prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow from banks may be subject to redetermination based on changes in prices. In addition, we may have ceiling test writedowns when prices decline. Lower prices may also reduce the amount of crude oil and natural gas that can be produced economically. Thus, we may experience material increases or decreases in reserve quantities solely as a result of price changes and not as a result of drilling or well performance.

Oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Our financial results are more sensitive to movements in natural gas prices than oil prices because most of our production and reserves are natural gas.

Changes in oil and gas prices impact both estimated future net revenue and the estimated quantity of proved reserves. Any reduction in reserves, including reductions due to price fluctuations, can reduce the borrowing base under our revolving credit facility and adversely affect the amount of cash flow available for capital expenditures and our ability to obtain additional capital for our exploration and development activities.

Lower oil and gas prices and other factors may cause us to record ceiling test writedowns.

Lower oil and gas prices increase the risk of ceiling limitation write-downs. We use the full cost method to account for oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop crude oil and natural gas properties. Under the full cost accounting rules, the net capitalized cost of crude oil and natural gas properties may not exceed a “ceiling limit” which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10% plus the lower of cost or fair market value of unproved properties. If net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess against earnings. This is called a “ceiling test writedown.” Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test writedown does not impact cash flow from operating activities, but does reduce stockholders’ equity and earnings. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when oil and natural gas prices are low.

Information concerning our reserves and future net revenues estimates is inherently uncertain.

Estimates of oil and gas reserves, by necessity, are projections based on engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, such as future production, oil and gas prices, operating costs, development costs and remedial costs, all of which may vary considerably from actual results. As a result, estimates of the economically recoverable quantities of oil and gas and of future net cash flows expected therefrom may vary substantially. Moreover, there can be no assurance that our reserves will ultimately be produced or that any undeveloped reserves will be developed. As required by the SEC, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower.

We must replace reserves we produce.

Our future success depends upon our ability to find, develop or acquire additional, economically recoverable oil and gas reserves. Our proved reserves will generally decline as reserves are depleted, except to the extent that we can find, develop or acquire replacement reserves. One offset to the obvious benefits afforded by higher product prices especially for small to mid-cap companies in this industry, is that quality domestic oil and gas reserves are becoming harder to find. Reserves to be produced from undiscovered reservoirs appear to be smaller, and the risks to find these reserves are greater. Reports from the Energy Information Administration indicate that on-shore domestic finding costs are on the rise, and that the average reserves added per well are declining.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business.

We plan to continue growing our reserves through acquisitions. Acquired properties can be subject to significant unknown liabilities. Prior to completing an acquisition, it is generally not feasible to conduct a detailed review of each individual property to be acquired in an acquisition. Even a detailed review or inspection of each property may not reveal all existing or potential liabilities associated with owning or operating the property. Moreover, some potential liabilities, such as environmental liabilities related to groundwater contamination, may not be discovered even when a review or inspection is performed. Our initial reserve estimates for acquired properties may be inaccurate. Downward adjustments to our estimated proved reserves, including reserves added through acquisitions, could require us to write down the carrying value of our oil and gas properties, which would reduce our earnings and our stockholders' equity. Our failure to integrate acquired businesses successfully into our existing business could result in our incurring unanticipated expenses and losses. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

Drilling and operating activities are high risk activities that subject us to a variety of factors that we can not control.

These factors include availability of workover and drilling rigs, well blowouts, cratering, explosions, fires, formations with abnormal pressures, pollution, releases of toxic gases and other environmental hazards and risks. Any of these operating hazards could result in substantial losses to us. In addition, we incur the risk that no commercially productive reservoirs will be encountered, and there is no assurance that we will recover all or any portion of its investment in wells drilled or re-entered.

Our business depends on oil and natural gas transportation facilities which are owned by others.

The marketability of our production depends in part on the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could all affect our ability to produce and market our oil and gas.

We may not be insured against all of the operating hazards to which our business is exposed.

Our operations are subject to all the risks inherent in the exploration for, and development and production of oil and gas including blowouts, fires and other casualties. We maintain insurance coverage customary for operations of a similar nature, but losses could arise from uninsured risks or in amounts in excess of existing insurance coverage.

The oil and gas industry is highly competitive.

Competition for oil and gas reserve acquisitions is significant. We may compete with major oil and gas companies, other independent oil and gas companies and individual producers and operators, some of which have financial and personnel resources substantially in excess of those available to us. As a result, we may be placed at a competitive disadvantage. Our ability to acquire and develop additional properties in the future will depend upon our ability to select and acquire suitable producing properties and prospects for future development activities. In addition, the oil and gas industry as a whole also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. The price and availability of alternative energy sources could adversely affect our revenue. The market for our oil, gas and natural gas liquids production depends on factors beyond our control, including domestic and foreign political conditions, the overall level of supply of and demand for oil, gas and natural gas liquids, the price of imports of oil and gas, weather conditions, the price and availability of alternative fuels, the proximity and capacity of gas pipelines and other transportation facilities and overall economic conditions.

Our business is subject to extensive environmental regulations, and to laws that can give rise to liabilities from environmental contamination.

Our operations are subject to extensive federal, state and local environmental laws and regulations, which impose limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities to investigate or remediate contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage, may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate. Such liabilities may arise even where the contamination does not result from any noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. Environmental requirements generally have become more stringent in recent years, and compliance with those requirements more expensive.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties consist primarily of oil and gas wells and our ownership in leasehold acreage, both developed and undeveloped. As of March 31, 2008, we had interests in 2,208 gross (23 net) oil and gas wells and owned leasehold interests in approximately 301,403 gross (2,955 net) acres.

Oil and Natural Gas Reserves

Estimates of our proved oil and gas reserves, which are located entirely within the United States, were prepared in accordance with the guidelines established by the SEC and Financial Accounting Standards Board ("FASB"). The estimates as of March 31, 2008, 2007 and 2006 are based on evaluations prepared by Joe C. Neal and Associates, Petroleum Consultants. For information concerning our costs incurred for oil and gas operations, net revenues from oil and gas production, estimated future net revenues attributable to our oil and gas reserves, present value of future net revenues discounted at 10% and changes therein, see Notes to the Company's consolidated financial statements.

We emphasize that reserve estimates are inherently imprecise and there can be no assurance that the reserves set forth below will be ultimately realized. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from the assumptions and estimates. Any significant variance could materially affect the estimated quantities and value of our oil and gas reserves, which in turn may adversely affect our cash flow, results of operations and the availability of capital resources.

In accordance with applicable financial accounting and reporting standards of the SEC, the estimates of our proved reserves and the present value of proved reserves set forth herein are made using oil and gas sales prices estimated to be in effect as of the date of such reserve estimates and are held constant throughout the life of the properties. Actual future prices and costs may be materially higher or lower than those as of the date of the estimate. The timing of both the production and the expenses with respect to the development and production of oil and gas properties will affect the timing of future net cash flows from proved reserves and their present value. Except to the extent that we acquire additional properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced.

We have not filed any other oil or gas reserve estimates or included any such estimates in reports to other federal or foreign governmental authority or agency within the last twelve months.

Our estimated proved oil and gas reserves and present value of estimated future net revenues from proved oil and gas reserves in the periods ended March 31 are summarized below.

PROVED RESERVES

	March 31,		
	2008	2007	2006
Oil (Bbls):			
Proved developed – Producing	117,874	110,060	85,091
Proved developed – Non-producing	3,754	1,432	1,432
Proved undeveloped	95,599	108,263	96,557

Total		217,227		219,755		183,080
Natural gas (Mcf):						
Proved developed – Producing		3,954,269		2,892,964		2,816,566
Proved developed – Non-producing		1,096,174		1,075,376		1,074,550
Proved undeveloped		2,806,179		2,936,708		2,806,070
Total		7,856,622		6,905,048		6,697,186
Present value of estimated future net revenues before income taxes(PV-10) (1)	$	40,899,620	$	26,172,460	$	23,290,420
Present value of future income tax discounted at 10%		(8,401,620)		(5,965,460)		(5,366,420)
Standardized measure of discounted future net cash flows (2)	$	32,498,000	$	20,207,000	$	17,924,000

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(1) Non-GAAP Financial Measure and Reconciliation (unaudited) – PV-10 is derived from the standardized measure of discounted future net cash flows which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

(2) Standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and a discount factor of 10% to net proved reserves, taking into account the effect of future income taxes.

Productive Wells and Acreage

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. Wells that are completed in more than one producing zone are counted as one well. The following table indicates our productive wells as of March 31, 2008:

	Gross	Net
Oil	1,335	13
Gas	873	10
Total Productive Wells	2,208	23

The following table sets forth the approximate developed acreage in which we held a leasehold mineral or other interest as of March 31, 2008.

	Developed Acres	
	Gross	Net
Texas	154,074	2,536
New Mexico	21,237	155
North Dakota	27,119	25
Louisiana	33,365	37
Oklahoma	42,482	167
Montana	9,788	5
Kansas	8,520	24
Wyoming	3,298	5
Colorado	1,200	1
Arkansas	320	—
Total	301,403	2,955

Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves. A gross acre is an acre in which an interest is owned. A net acre is deemed to exist when the sum of fractional ownership interests in gross acres equals one. The number of net acres is the sum of the fractional interests owned in gross acres. As of March 31, 2008, we own approximately 1,477 gross and 737 net acres of material undeveloped acreage located in Texas.

Drilling Activities

The following table sets forth our drilling activity in wells in which we own a working interest for the years ended March 31:

	Year Ended March 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	4	.56	—	—	3	.03
Nonproductive	1	.09	—	—	—	—
Total	5	.65	—	—	3	.03
Development Wells						
Productive	27	.42	47	.22	12	.05
Nonproductive	1	.06	—	—	—	—
Total	28	.48	47	.22	12	.05

The information contained in the foregoing table should not be considered indicative of future drilling performance, nor should it be assumed that there is any necessary correlation between the number of productive wells drilled and the amount of oil and gas that may ultimately be recovered by us.

Net Production, Unit Prices and Costs

The following table summarizes our net oil and natural gas production, the average sales price per barrel of oil and per thousand cubic feet ("mcf") of natural gas produced and the average production (lifting) cost per unit of production for the years ended March 31:

	Year Ended March 31,		
	2008	2007	2006
Oil (a):			
Production (Bbls)	17,504	16,738	17,118
Revenue	$ 1,348,725	$ 995,557	$ 938,681
Average Bbls per day	48	46	47
Average sales price per Bbl	$ 77.05	$ 59.48	$ 54.84
Gas (b):			
Production (Mcf)	379,048	339,174	370,069
Revenue	$ 2,539,230	$ 1,973,768	$ 2,777,883
Average Mcf per day	1,038	929	1,014
Average sales price per Mcf	$ 6.70	$ 5.82	$ 7.51
Production cost:			
Production cost	$ 1,240,305	$ 870,778	$ 843,927
Equivalent Mcf (c)	484,072	439,602	472,777
Production cost per equivalent Mcf	$ 2.56	$ 1.98	$ 1.79
Production cost per sales dollar	$ 0.32	$ 0.29	$ 0.23
Total oil and gas revenues	$ 3,887,955	$ 2,969,325	$ 3,716,564

(a) Includes condensate.

(b) Includes natural gas products.

(c) Oil production is converted to equivalent mcf at the rate of 6 mcf per barrel (“bbl”), representing the estimated relative energy content of natural gas to oil.

ITEM 3. LEGAL PROCEEDINGS

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. We are currently a party to a lawsuit that is being filed against the drilling company of a well in which we have a working interest of approximately 6.5%. We are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under various environmental protection statutes or other regulations to which we are subject.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter ended March 31, 2008.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER REPURCHASE OF EQUITY SECURITIES

In September 2003, our common stock began trading on the American Stock Exchange under the symbol "MXC". Prior to September 2003, the Company's common stock was traded on the over-the-counter market bulletin board under the symbol "MEXC". The registrar and transfer agent is Computershare Trust Company N.A., P.O. Box 1596, Denver, Colorado, 80201 (Tel: 303-262-0600). As of March 31, 2008, we had approximately 1,300 shareholders of record and 1,841,366 shares issued.

PRICE RANGE OF COMMON STOCK

	High	Low
2008:		
April - June 2007 (1)	$ 5.49	$ 5.05
July - September 2007 (1)	5.91	4.33
October - December 2007 (1)	5.47	3.90
January - March 2008 (1)	4.50	3.43
2007:		
April - June 2006 (1)	$ 11.19	$ 6.35
July - September 2006(1)	8.81	6.09
October - December 2006 (1)	7.27	5.80
January - March 2007 (1)	6.29	5.15

(1) Reflects the high and low sales prices for the Company's Common Stock, as reported on the American Stock Exchange.

On June 16, 2008, the closing price was $44.63.

Dividends

We have never declared or paid any cash dividends on our common stock. We currently intend to retain future earnings and other cash resources, if any, for the operation and development of our business and do not anticipate paying any cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion. In addition, our current bank loan prohibits us from paying cash dividends on our common stock. Any future dividends may also be restricted by any loan agreements which we may enter into from time to time.

Issuer Repurchases

In June 2006, the board of directors authorized the use of up to $250,000 in addition to a prior authorization of $250,000 to repurchase shares of our common stock for the treasury account. Throughout fiscal 2007, we repurchased 30,000 shares at an aggregate cost of $183,309. Of these shares, 20,000 were shares issued pursuant to options exercised by a consultant and repurchased by Mexco. During fiscal 2008, we repurchased 24,475 shares at an aggregate cost of $ 119,093.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

	Year Ended March 31,				
	2008	2007	2006	2005	2004
Statement of Operations:					
Operating revenues	$ 3,899,408	$ 2,971,717	$ 3,719,643	$ 2,969,826	$ 2,915,355
Operating income	1,031,437	594,876	1,114,966	924,230	785,739
Other income (expense)	(100,199)	(19,376)	(95,820)	(88,408)	(82,766)
Net income	$ 713,644	$ 608,385	$ 788,805	$ 577,527	$ 429,846
Net income per share – basic (1)	$ 0.40	$ 0.35	$ 0.45	$ 0.33	$ 0.25
Net income per share – diluted (1)	$ 0.40	$ 0.33	$ 0.43	$ 0.32	$ 0.24
Weighted average shares outstanding – basic	1,767,777	1,761,344	1,733,890	1,734,726	1,736,047
Weighted average shares outstanding – diluted	1,773,049	1,819,969	1,827,026	1,801,167	1,802,300
Balance Sheet:					
Property and equipment, net	$ 11,982,949	$ 9,337,566	$ 8,399,929	$ 8,484,743	$ 7,647,284
Total assets	13,202,659	9,958,980	8,978,324	9,303,149	8,172,464
Total debt	2,600,000	700,000	600,000	1,990,000	1,700,000
Stockholders' equity	8,460,064	7,775,636	6,898,996	6,038,195	5,435,219
Cash Flow:					
Cash provided by operations	$ 1,474,764	$ 1,325,024	$ 1,900,665	$ 1,451,628	$ 1,517,479

(1) Year 2004 includes a cumulative effect of change in accounting principle (Cumulative Effect) loss of $0.06 related to the adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, Asset Retirement Obligations.

Selected Quarterly Financial Data (Unaudited)

	FISCAL 2008			
	4TH QTR	3RD QTR	2ND QTR	1ST QTR
Oil and gas revenue	$ 1,245,653	$ 952,211	$ 839,947	$ 850,144
Operating profit	613,742	345,203	4,344	68,148
Net income	466,480	221,114	(8,756)	34,806
Net income per share-basic	0.27	0.13	-	0.02
Net income per share-diluted	0.27	0.12	-	0.02

	FISCAL 2007			
	4TH QTR	3RD QTR	2ND QTR	1ST QTR
Oil and gas revenue	$ 755,184	$ 663,031	$ 773,698	$ 777,412
Operating profit	110,106	109,906	229,920	144,944

Net income	183,481	67,080	130,534	227,290
Net income per share-basic	0.11	0.04	0.07	0.13
Net income per share-diluted	0.10	0.04	0.07	0.12

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

The following discussion is intended to provide information relevant to an understanding of our financial condition, changes in our financial condition and our results of operations and cash flows and should be read in conjunction with our consolidated financial statements and notes thereto included elsewhere in this Form 10-K.

Liquidity and Capital Resources and Commitments

Historically, we have funded our operations, acquisitions, exploration and development expenditures from cash generated by operating activities, bank borrowings and issuance of common stock. Our primary financial resource is our base of oil and gas reserves. We pledge our producing oil and gas properties to secure our revolving line of credit.

Our long term strategy is on increasing profit margins while concentrating on obtaining reserves with low cost operations by acquiring and developing primarily gas properties and secondarily oil properties with potential for long-lived production.

In fiscal 2008, we primarily used cash provided by operations ($1,474,764) to fund oil and gas property acquisitions and development ($3,060,194). We had working capital of $627,674 as of March 31, 2008 compared to working capital of $446,831 as of March 31, 2007, an increase of $180,483. This was mainly as a result of an increase in accounts receivable and cash and cash equivalents. The accounts receivable increase was related to drilling costs billed to co-owners on wells we operate in Loving and Reeves Counties.

During fiscal 2008, we participated in the drilling of a well in Crane County, Texas of which our costs are approximately $172,000. The well is scheduled for additional procedures including acidizing and possible new pay zones may be added in fiscal 2009.

We also participated in the drilling of a well in Lea County, New Mexico. The initial well failed due to mechanical reasons; however, other methods are being evaluated for the exploration and development of this project. Total costs incurred related to this project are approximately $237,000 through March 31, 2008. A lawsuit has been filed against the drilling company to recover damages due to this failure.

We are currently participating in the drilling and completion of a well in Borden County, Texas. Costs incurred related to this project are approximately $326,000. This oil well began producing in March 2008.

During fiscal 2008, we participated in an exploratory well in San Patricio County, Texas. This well has been completed and began producing natural gas as well as oil in April 2008. Costs incurred for this project are approximately $166,000.

We are in the process of acquiring mineral, royalty and surface interests in several counties, mainly in Texas. Purchases incurred related to this project through May 2008 are approximately $34,000.

During the third quarter of fiscal 2008, we acted as operator and drilled an exploratory well in Loving County, Texas. This well has been completed and based on a four point test by an independent testing firm, was calculated to produce at an absolute open flow rate of 12,773,000 cubic feet of natural gas per day. During this four hour test the well actually produced 1,366,000 cubic feet of natural gas, 26 barrels of 63 gravity condensate and 12 barrels of water on chokes ranging from 11/64 to 15/64 inches. Previously the well had been shut in for a period in excess of 72 hours. The rates at which this will be produced and sold have not yet been determined and may be substantially different from these potential tests, based on regulatory and engineering considerations as well as performance of the well over longer periods of time. Our share of the costs incurred for this project through April 30, 2008 is approximately $345,000.

On December 31, 2007, we purchased 122 mineral acres amounting to approximately 21.45% royalty interest in Tarrant County, Texas for $1,850,000. At the time of purchase, this property contained one producing well in the Newark East (Barnett Shale) Field. Subsequently, two additional wells have been completed. All three wells are now producing natural gas into a sales pipeline. A director and employee of the Company received a finder's fee of 2.5% ORRI in lieu of a cash payment as disclosed on Form 8-K dated December 31, 2007.

On June 6, 2008 we purchased mineral and royalty interests contained in an aggregate of 522 acres with royalties varying from .126% to .385% in 6 producing natural gas wells and 5 proven undeveloped well locations in the Newark East (Barnett-Shale) Field of Tarrant County, Texas. There are an additional 6 potential drill sites on this acreage.

During the fourth quarter of fiscal 2008, we drilled a gas well in Reeves County, Texas. This well has been completed and began producing in April 2008. Our share of the costs incurred for this project is approximately $181,000.

We are participating in several other projects and are reviewing several other projects in which we may participate. The cost of such projects would be funded, to the extent possible, from existing cash balances and cash flow from operations. The remainder may be funded through borrowings on the credit facility. See Note 3 of Notes to Consolidated Financial Statements for a description of our revolving credit agreement with Bank of America, N.A.

Crude oil and natural gas prices have fluctuated significantly in recent years as well as in recent months. Fluctuations in price have a significant impact on our financial condition and liquidity. However, management is of the opinion that cash flow from operations and funds available from financing will be sufficient to provide adequate liquidity for the next fiscal year.

Results of Operations

Fiscal 2008 Compared to Fiscal 2007

Net income increased from $608,385 for the year ended March 31, 2007 to $713,644 for the year ended March 31, 2008, an increase of $105,259 or 17%.

Oil and gas sales. Revenue from oil and gas sales increased from $2,969,325 in 2007 to $3,887,955 in 2008, an increase of $918,630 or 31%. This increase was attributable to an increase in oil and gas prices and oil and gas production. The average oil price increased from $59.48 per bbl in 2007 to $77.05 per bbl in 2008, an increase of $17.57 per bbl or 30%. The average gas price increased from $5.82 in 2007 to $6.70 per mcf in 2008, an increase of $.88 per mcf or 15%.

Production and exploration. Production costs increased from $870,778 in 2007 to $1,240,305 in 2008, an increase of $369,527 or 42%. This is primarily a result of an increase in repairs and maintenance to operated wells in the El Cinco field and increased production taxes due to the increase in oil and gas sales and production. Oil production increased from 16,738 bbls in 2007 to 17,504 bbls in 2008, an increase of 766 bbls or 5%. Gas production increased from 339,174 mcf in 2007 to 379,048 mcf in 2008, an increase of 39,874 mcf or 12%.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased from $652,826 in 2007 to $779,618 in 2008, an increase of $126,792 or 19%. This is the result of an increase in production and an increase in full cost pool partially offset by an increase in reserves.

General and administrative expenses. General and administrative expenses decreased from $829,180 in 2007 to $821,786 in 2008, a decrease of $7,394 or 1%. This decrease was attributable to a decrease in stock option compensation expense partially offset by an increase in engineering and geological services due to the continuous evaluation of projects.

Interest expense. Interest expense increased from $24,046 in 2007 to $105,312 in 2008, an increase of $81,266 or 338%. This increase was attributable to an increase in average borrowings during the current fiscal year.

Income taxes. Income tax expense increased from a tax benefit of $28,050 in 2007 to a tax expense of $217,594 in 2008, an increase of $245,644. This increase was attributable to our increased income and only a small revision of prior year estimates.

Fiscal 2007 Compared to Fiscal 2006

Oil and gas sales. Oil and gas sales decreased from $3,716,564 in 2006 to $2,969,325 in 2007, a decrease of $747,239 or 20%. This decrease was attributable to a decrease in gas prices and oil and gas production. The average oil price increased from $54.84 per bbl in 2006 to $59.48 per bbl in 2007, an increase of $4.64 per bbl or 8%. The average gas price decreased from $7.51 in 2006 to $5.82 per mcf in 2007, a decrease of $1.69 per mcf or 22%.

Production and exploration. Production costs increased from $843,927 in 2006 to $870,778 in 2007, an increase of $26,851 or 3%. This is primarily a result of an increase in lease operating expenses on our operated properties. Oil production decreased from 17,118 bbls in 2006 to 16,738 bbls in 2007, a decrease of 380 bbls or 2%. Gas production decreased from 370,069 mcf in 2006 to 339,174 mcf in 2007, a decrease of 30,895 mcf or 8%. Such decreases primarily were due to normal decline in production.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased from $658,365 in 2006 to $652,826 in 2007, a decrease of $5,539 or 1%. This is partially the result of a decrease in production and an increase in reserves.

General and administrative expenses. General and administrative expenses increased from $817,332 in 2006 to $829,180 in 2007, an increase of $11,848 or 1%. This increase was attributable to the adoption of FAS 123(R) offset by a decrease in expenses related to Russian projects in fiscal 2007.

Interest expense. Interest expense decreased from $98,657 in 2006 to $24,046 in 2007, a decrease of $74,611 or 76%. This decrease was attributable to a decrease in average borrowings during the current fiscal year.

Income taxes. Income tax expense decreased from $272,140 in 2006 to a tax benefit of $28,050 in 2007, a decrease of $300,190. This decrease was partially attributable to our decreased income and the write-off of expired leases. We also had a current tax deduction for options exercised during fiscal year 2007.

Alternative Capital Resources

Although we have primarily used cash from operating activities and funding from the line of credit as our primary capital resources, we have in the past, and could in the future, use alternative capital resources. These could include joint ventures, carried working interests and the sale of assets and/or issuances of common stock through a private placement or public offering of our common stock.

Contractual Obligations

We have no off-balance sheet debt or unrecorded obligations and have not guaranteed the debt of any other party. The following table summarizes our future payments we are obligated to make based on agreements in place as of March 31, 2008:

		Payments Due In:		
	Total	1 year	1-3 years	3 years
Contractual obligations:				
Secured bank line of credit	$ 2,600,000	$ —	$ 2,600,000	$ —

These amounts represent the balances outstanding under the bank line of credit. These repayments assume that interest will be paid on a monthly basis and that no additional funds will be drawn.

Other Matters

Critical Accounting Policies and Estimates

In preparing financial statements, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, management reviews its estimates, including those related to litigation, environmental liabilities, income taxes, fair value and determination of proved reserves. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

The following represents those policies that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

Full Cost Method of Accounting for Crude Oil and Natural Gas Activities. SEC Regulation S-X defines the financial accounting and reporting standards for companies engaged in crude oil and natural gas activities. Two methods are prescribed: the successful efforts method and the full cost method. We have chosen to follow the full cost method under which all costs associated with property acquisition, exploration and development are capitalized. We also capitalize internal costs that can be directly identified with acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Effective with the adoption of SFAS No. 143 in 2003, the carrying amount of oil and gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation when incurred. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of crude oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of crude oil and natural gas properties under the successful efforts method. As a result our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization (“DD&A”) rate on our crude oil and natural gas properties.

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us more susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. Our crude oil and natural gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from the full cost method of accounting.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas exploration and development activities are required to perform a ceiling test each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The test determines a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from proved crude oil and natural gas reserves, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of crude oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are depressed or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or if purchasers cancel long-term contracts for natural gas production. An expense recorded in one period may not be reversed in a subsequent period even though higher crude oil and natural gas prices may have increased the ceiling applicable to the subsequent period.

Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions;
- and the judgment of the persons preparing the estimate.

Our proved reserve information included in this report was based on evaluations prepared by independent petroleum engineers. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

It should not be assumed that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

The estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields.

Use of Estimates. In preparing financial statements in conformity with accounting principles generally accepted in the United States of America, management is required to make informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. Although management believes its estimates and assumptions are reasonable, actual results may differ materially from those estimates. Significant estimates affecting these financial statements include the estimated quantities of proved oil and gas reserves, the related present value of estimated future net cash flows and the future development, dismantlement and abandonment costs.

Revenue Recognition. We recognize crude oil and natural gas revenue from our interest in producing wells as crude oil and natural gas is sold from those wells, net of royalties. We utilize the sales method to account for gas production volume imbalances. Under this method, income is recorded based on our net revenue interest in production taken for delivery. We had no material gas imbalances.

Excluded Costs. Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent investments in unproved properties and major development projects. These costs are excluded until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed at least quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized (the DD&A pool) or a charge is made against earnings for those international operations where a reserve base has not yet been established. Impairments transferred to the DD&A pool increase the DD&A rate. Costs excluded for oil and gas properties are generally classified and evaluated as significant or individually insignificant properties.

Asset Retirement Obligations (“ARO”). The estimated costs of restoration and removal of facilities are accrued. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated by the units of production method. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in the full cost amortization base and amortize these costs as a component of our depletion expense.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (“SFAS 157”), which provides guidance for using fair value to measure assets and liabilities. The pronouncement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, the FASB having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurement. SFAS 157, as originally issued, was effective for fiscal years beginning after November 15, 2007. However, in February 2008, the FASB issued FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157,* which provides a one year delay of the effective date of FAS 157 as it relates to nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). SFAS 157 as it relates to financial assets and liabilities will be effective as of the beginning of our 2009 fiscal year. Management is currently evaluating the impact of SFAS 157 on our financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Liabilities – Including an amendment of FASB Statement No. 115* ("SFAS 159"). SFAS 159 permits entities to choose to measure certain financial assets and liabilities at fair value. Unrealized gains and losses, arising subsequent to adoption, are reported in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. Management does not anticipate that the adoption of SFAS 159 will have a material effect on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk Factors

The primary source of market risk for us includes fluctuations in commodity prices and interest rates. All of our financial instruments are for purposes other than trading. At March 31, 2008, we had not entered into any hedge arrangements, commodity swap agreements, commodity futures, options or other similar agreements relating to crude oil and natural gas.

Interest Rate Risk. Our variable rate bank debt is tied to prime rate. On March 31, 2008 we had an outstanding loan balance of $2,600,000 under our $5.0 million revolving credit agreement, which bears interest at the prime rate, which varies from time to time. If the interest rate on our bank debt increases or decreases by one percentage point, our annual pretax income would change by $26,000 based on borrowings at March 31, 2008.

Credit Risk. Credit risk is the risk of loss as a result of nonperformance by other parties of their contractual obligations. Our primary credit risk is related to oil and gas production sold to various purchasers and the receivables are generally not collateralized. At March 31, 2008, our largest credit risk associated with any single purchaser was $224,541. We are also exposed to credit risk in the event of nonperformance from any of our working interest partners. At March 31, 2008, our largest credit risk associated with any working interest partner was $31,515. We have not experienced any significant credit losses.

Energy Price Risk. Our most significant market risk is the pricing for natural gas and crude oil. Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. These factors include the level of global demand for petroleum products, foreign supply of oil and gas, the establishment of and compliance with production quotas by oil-exporting countries, weather conditions, the price and availability of alternative fuels and overall economic conditions, both foreign and domestic. We cannot predict future oil and gas prices with any degree of certainty and expect energy prices to remain volatile and unpredictable. If energy prices decline significantly, revenues and cash flow would significantly decline. In addition, a noncash write-down of our oil and gas properties could be required under full cost accounting rules if prices declined significantly, even if it is only for a short period of time. See Critical Accounting Policies and Estimates — Ceiling Test under Item 7 of this Form 10-K. Sustained weakness in oil and gas prices may also reduce the amount of net oil and gas reserves that we can produce economically. Any reduction in reserves, including reductions due to price fluctuations, can reduce the borrowing base under our revolving credit facility and adversely affect our liquidity and our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If the average oil price had increased or decreased by one dollar per barrel for fiscal 2008, our pretax income would have changed by $17,504. If the average gas price had increased or decreased by one dollar per mcf for fiscal 2008, our pretax income would have changed by $379,048.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this Item appears on pages F1 through F17 hereof and are incorporated herein by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

ITEM 9A. CONTROLS AND PROCEDURES

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Our principal executive officer and principal financial officer evaluated the effectiveness of our internal control over financial reporting based on the framework in INTERNAL CONTROL-INTEGRATED FRAMEWORK issued by the Committee of Sponsoring Organizations of the Treadway Commission. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of March 31, 2008.

We maintain disclosure controls and procedures to ensure that the information we must disclose in our filings with the SEC is recorded, processed, summarized and reported on a timely basis. Our principal executive officer and principal financial officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures, as defined in Exchange Act Rules 13a-15(e) and 15d-15(e), as of March 31, 2008. Based on such evaluation, such officers have concluded that, as of March 31, 2008, our disclosure controls and procedures were effective in timely alerting them to material information relating to us (and our consolidated subsidiaries) required to be included in our periodic SEC filings.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required regarding directors of the Company and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the Proxy Statement for our Annual Meeting of Stockholders, which will be filed with the SEC not later than July 18, 2008.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to executive officers of the Company is set forth in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the Proxy Statement for our Annual Meeting of Stockholders, which will be filed with the SEC no later than July 18, 2008.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this Item is incorporated by reference to the Proxy Statement for our Annual Meeting of Stockholders, which will be filed with the SEC no later than July 18, 2008.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is incorporated by reference to the Proxy Statement for our Annual Meeting of Stockholders, which will be filed with the SEC no later than July 18, 2008.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the Proxy Statement for our Annual Meeting of Stockholders, which will be filed with the SEC no later than July 18, 2008.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements and Schedules. For a list of the consolidated financial statements filed as part of this Form 10-K, see the "Index to Consolidated Financial Statements" set forth on page F1 of this report. No schedules are required to be filed because of the absence of conditions under which they would be required or because the required information is set forth in the financial statements or notes thereto referred to above.

Exhibits. For a list of the exhibits required by this Item and accompanying this Form 10-K see the "Index to Exhibits" set forth on page F18 of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on behalf of the undersigned thereunto duly authorized.

MEXCO ENERGY CORPORATION

By: /s/ Nicholas C. Taylor
Nicholas C. Taylor
Chief Executive Officer and President

Dated: June 19, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below as of June 19, 2008, by the following persons on behalf of the Company and in the capacity indicated.

/s/ Thomas R. Craddick
Thomas R. Craddick
Director

/s/ Thomas Graham, Jr.
Thomas Graham, Jr.
Chairman of the Board
of Directors

/s/ Arden Grover
Arden Grover
Director

/s/ Jack D. Ladd
Jack D. Ladd
Director

/s/ Tamala L. McComic
Tamala L. McComic
Chief Financial Officer,
Vice President,
Treasurer
and Assistant Secretary

/s/ Jeffry A. Smith
Jeffry A. Smith
Director

/s/ Nicholas C. Taylor
Nicholas C. Taylor
Chief Executive
Officer, President and
Director

/s/ Donna Gail Yanko
Donna Gail Yanko

Vice President,
Secretary and Director

Glossary of Abbreviations and Terms

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this Form 10-K.

Bbl. One stock tank barrel, or 42 U.S. gallons of liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Credit Facility. A line of credit provided by a group of banks, secured by oil and gas properties.

DD&A. Refers to depreciation, depletion and amortization of the Company's property and equipment.

Developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

Development well. A well drilled into a proved oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploration. The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Extensions and discoveries. As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or wells. Refers to the total acres or wells in which the Company owns any amount of working interest.

Lease. An instrument which grants to another (the lessee) the exclusive right to enter and explore for, drill for, produce, store and remove oil and natural gas from the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions.

Mcfe. One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf for each Bbl of oil.

MMcf. One million cubic feet of natural gas at standard atmospheric conditions.

MMcfe. One million cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf for each Bbl of oil.

Natural gas liquids. Liquid hydrocarbons that have been extracted from natural gas, such as ethane, propane, butane and natural gasoline.

Net acres or wells. Refers to gross acres or wells multiplied, in each case, by the percentage interest owned by the Company.

Net production. Oil and gas production that is owned by the Company, less royalties and production due others.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

Oil. Crude oil or condensate.

Operator. The individual or company responsible for the exploration, development and production of an oil or natural gas well or lease.

Overriding royalty interest ("ORRI"). A royalty interest that is created out of the operating or working interest. Its term is coextensive with that of the operating interest from which it was created.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of proved reserves. The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, (ii) non-property related expenses such as general and administrative expenses, debt service and future income tax expense, or (iii) depreciation, depletion and amortization.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed operating and production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed nonproducing reserves (PDNP). Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves (PDP). Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Proved developed reserves. The combination of proved developed producing and proved developed nonproducing reserves.

Proved reserves. The estimated quantities of oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves (PUD). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC.

Recompletion. A process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Re-entry. Entering an existing well bore to redrill or repair.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage, or of the proceeds of the sale thereof, but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Standardized measure of discounted future net cash flows. The present value of proved reserves, as adjusted to give effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, and (ii) estimated future income taxes.

Undeveloped acreage. Leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest is entitled will be smaller than the share of costs that the working interest owner is required to bear to the extent of any royalty burden.

Workover. Operations on a producing well to restore or increase production.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Mexco Energy Corporation

We have audited the accompanying consolidated balance sheets of Mexco Energy Corporation and Subsidiaries as of March 31, 2008 and 2007 and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended March 31, 2008. 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. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Mexco Energy Corporation and Subsidiaries as of March 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 10 to the financial statements, effective April 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*, and changed its method of accounting for stock-based compensation.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
June 23, 2008

Mexco Energy Corporation and Subsidiaries
CONSOLIDATED BALANCE SHEETS
As of March 31,

		2008		2007
ASSETS				
Current assets				
Cash and cash equivalents	$	303,617	$	72,537
Accounts receivable:				
Oil and gas sales		758,459		399,659
Trade		102,403		2,987
Related parties		12,659		-
Income tax receivable		-		59,736
Prepaid costs and expenses		22,062		65,986
Total current assets		1,199,200		600,905
Investment in GazTex, LLC		20,509		20,509
Property and equipment, at cost				
Oil and gas properties, using the full cost method		23,941,483		20,526,431
Other		61,362		51,412
		24,002,845		20,577,843
Less accumulated depreciation, depletion, and amortization		12,019,895		11,240,277
Property and equipment, net		11,982,950		9,337,566
	$	13,202,659	$	9,958,980
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued expenses	$	571,526	$	154,074
Long-term debt		2,600,000		700,000
Asset retirement obligation		374,789		350,584
Deferred income tax liabilities		1,196,280		978,686
Stockholders' equity				
Preferred stock - $1.00 par value; 10,000,000 shares authorized; none outstanding		-		-
Common stock - $0.50 par value; 40,000,000 shares authorized; 1,841,366 and 1,840,366 shares issued; 1,757,366 and 1,780,841 shares outstanding as of March 31, 2008 and 2007, respectively		920,683		920,183
Additional paid-in capital		4,381,269		4,291,892
Retained earnings		3,584,729		2,871,085
Treasury stock, at cost (84,000 and 59,525 shares, respectively)		(426,617)		(307,524)
Total stockholders' equity				
		8,460,064		7,775,636
	$	13,202,659	$	9,958,980

The accompanying notes to the consolidated financial statements are an integral part of these statements.

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Mexco Energy Corporation and Subsidiaries
CONSOLIDATED STATEMENTS OF OPERATIONS
Year ended March 31,

	2008	2007	2006
Operating revenues:			
Oil and gas	$ 3,887,955	$ 2,969,325	$ 3,716,564
Other	11,453	2,392	3,079
Total operating revenues	3,899,408	2,971,717	3,719,643
Operating expenses:			
Production	1,240,305	870,778	843,927
Accretion of asset retirement obligation	26,262	24,057	23,436
Depreciation, depletion, and amortization	779,618	652,826	658,365
General and administrative	821,786	829,180	817,332
Impairment of long-term asset	-	-	261,617
Total operating expenses	2,867,971	2,376,841	2,604,677
Operating profit	1,031,437	594,876	1,114,966
Other income (expense):			
Interest income	5,113	4,670	2,837
Interest expense	(105,312)	(24,046)	(98,657)
Net other expense	(100,199)	(19,376)	(95,820)
Earnings before income taxes and minority interest	931,238	575,500	1,019,146
Income tax expense (benefit):			
Current	-	-	(19,312)
Deferred	217,594	(28,050)	291,452
	217,594	(28,050)	272,140
Earnings before minority interest	713,644	603,550	747,006
Minority interest in loss of subsidiary	-	4,835	41,799
Net income	$ 713,644	$ 608,385	$ 788,805
Net income per common share:			
Basic:	$ 0.40	$ 0.35	$ 0.45
Diluted:	$ 0.40	$ 0.33	$ 0.43

The accompanying notes to the consolidated financial statements
are an integral part of these statements.

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Mexco Energy Corporation and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock Par Value	Treasury Stock	Additional Paid-In Capital	Retained Earnings	Total Stockholders' Equity
Balance, April 1, 2005	$ 883,283	$ (145,575)	$ 3,826,592	$ 1,473,895	$ 6,038,195
Net income	-	-	-	788,805	788,805
Issuance of stock through options exercised	5,000	-	47,500	-	52,500
Stock based compensation	-	-	19,496	-	19,496
Balance, March 31, 2006	888,283	(145,575)	3,893,588	2,262,700	6,898,996
Net income	-	-	-	608,385	608,385
Purchase of stock	-	(183,309)	-	-	(183,309)
Issuance of stock through options exercised	30,900	-	258,750	-	289,650
Issuance of stock for property	-	21,360	-	-	21,360
Stock award	1,000	-	13,100	-	14,100
Stock based compensation	-	-	126,454	-	126,454
Balance, March 31, 2007	920,183	(307,524)	4,291,892	2,871,085	7,775,636
Net income	-	-	-	713,644	713,644
Purchase of stock	-	(119,093)	-	-	(119,093)
Issuance of stock through options exercised	500	-	3,500	-	4,000
Stock based compensation	-	-	85,877	-	85,877
Balance, March 31, 2008	$ 920,683	$ (426,617)	$ 4,381,269	$ 3,584,729	$ 8,460,064

	Share Activity		
	2008	2007	2006
Common stock issued			
At beginning of year	1,840,366	1,776,566	1,766,566
Issued	1,000	63,800	10,000
At end of year	1,841,366	1,840,366	1,776,566
Held in treasury			
At beginning of year	(59,525)	(33,525)	(33,525)
Acquisitions	(24,475)	(30,000)	-
Exchange for property	-	4,000	-
At end of year	(84,000)	(59,525)	(33,525)
Common shares outstanding at end of year	1,757,366	1,780,841	1,743,041

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Mexco Energy Corporation and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS
Year ended March 31,

	2008	2007	2006
Cash flows from operating activities:			
Net income	$ 713,644	$ 608,385	$ 788,805
Adjustments to reconcile net income to net cash provided by operating activities:			
Increase (decrease) in deferred tax liabilities	217,594	(28,050)	291,452
Excess tax benefit from share based payment arrangement	(1,100)	(14,191)	-
Stock-based compensation	85,877	126,454	19,496
Common stock issued to director	-	14,100	-
Depreciation, depletion, and amortization	779,618	652,826	658,365
Accretion of asset retirement obligations	26,262	24,057	23,436
Impairment of long-term asset	-	-	261,617
Minority interest in loss of GazTex, LLC	-	(4,835)	(41,799)
(Increase) decrease in accounts receivable	(411,139)	26,896	14,167
Decrease (increase) in prepaid expenses	43,924	(50,146)	(68,214)
Decrease in income taxes payable	-	-	(48,127)
Increase (decrease) in accounts payable and accrued expenses	20,084	(30,472)	1,467
Net cash provided by operating activities	1,474,764	1,325,024	1,900,665
Cash flows from investing activities:			
Additions to oil and gas properties	(3,060,194)	(1,545,023)	(676,633)
Proceeds from sale of oil and gas properties and equipment	40,452	28,016	65,532
Additions to other property and equipment	(9,950)	(11,564)	(2,993)
Net cash used in investing activities	(3,029,692)	(1,528,571)	(614,094)
Cash flows from financing activities:			
Acquisition of treasury stock	(119,093)	(90,809)	-
Proceeds from exercise of stock options	4,000	197,150	52,500
Reduction of long-term debt	(525,000)	(740,000)	(1,390,000)
Proceeds from long term debt	2,425,000	840,000	-
Minority interest contributions	-	4,835	18,488
Repurchase of OBTX, LLC stock	-	(2,051)	-
Excess tax benefit from share based payment arrangement	1,100	14,191	-
Net cash provided by (used in) financing activities	1,786,007	223,316	(1,319,012)
Net increase (decrease) in cash and cash equivalents	231,080	19,769	(32,441)
Cash and cash equivalents at beginning of year	72,537	52,768	85,209
Cash and cash equivalents at end of year	$ 303,617	$ 72,537	$ 52,768
Interest paid	$ 97,163	$ 22,736	$ 102,669

Income taxes paid	$	-	$	-	$	88,551
Supplemental disclosure of non-cash investing and financing activities:						
Issuance of common stock in exchange for oil and gas properties	$	-	$	21,360	$	-
Cashless exercise of stock options and repurchase of treasury shares	$	-	$	92,500	$	-
Percentage of royalty interest purchase issued as payment for finder's fee	$	46,250	$	-	$	-
Asset retirement obligations	$	36,729	$	46,355	$	2,851

The accompanying notes to the consolidated financial statements are an integral part of these statements.

MEXCO ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Operations

Mexco Energy Corporation (a Colorado corporation), its wholly owned subsidiaries, Forman Energy Corporation (a New York corporation) and OBTX, LLC (a Delaware limited liability company) (collectively, the "Company") are engaged in the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids ("NGLs"). Although most of the Company's oil and gas interests are centered in West Texas, we own producing properties and undeveloped acreage in ten states. Although most of our oil and gas interests are operated by others, we operate several properties in which we own an interest.

2. Summary of Significant Accounting Policies

Principles of Consolidation. The consolidated financial statements include the accounts of Mexco Energy Corporation and its wholly owned subsidiaries. All significant intercompany balances and transactions associated with the consolidated operations have been eliminated.

Estimates and Assumptions. In preparing financial statements in conformity with accounting principles generally accepted in the United States of America, management is required to make informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. Although management believes its estimates and assumptions are reasonable, actual results may differ materially from those estimates. Significant estimates affecting these financial statements include the estimated quantities of proved oil and gas reserves, the related present value of estimated future net cash flows, the future development, dismantlement and abandonment costs, fair value of stock options and income taxes.

Cash and Cash Equivalents. We consider all highly liquid debt instruments purchased with maturities of three months or less and money market funds to be cash equivalents. We maintain our cash in bank deposit accounts and money market funds, some of which are not federally insured. We have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk.

Oil and Gas Properties. Oil and gas properties are accounted for using the full cost method of accounting as defined by the SEC. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation when incurred. Generally, no gains or losses are recognized on the sale or disposition of oil and gas properties.

Excluded Costs. Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent investments in unproved properties and major development projects. These costs are excluded until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed at least quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized (the depreciation, depletion and amortization ("DD&A") pool). Impairments transferred to the DD&A pool increase the DD&A rate.

Depreciation, Depletion and Amortization. The depreciable base for oil and gas properties includes the sum of capitalized costs, net of accumulated DD&A, estimated future development costs and asset retirement costs not accrued in oil and gas properties, less costs excluded from amortization and salvage. The depreciable base of oil and gas properties is amortized using the unit-of-production method.

Ceiling Test. Under the full cost method of accounting, a ceiling test is performed each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test determines a limit, on a country-by-country basis, on the book value of oil and gas properties. The capitalized costs of proved oil and gas properties, net of accumulated DD&A and the related deferred income taxes, may not exceed the estimated future net cash flows from proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, generally using prices in effect at the end of the period held flat for the life of production and including the effect of derivative contracts that qualify as cash flow hedges, discounted at 10%, net of related tax effects, plus the cost of unevaluated properties and major development projects excluded from the costs being amortized. If capitalized costs exceed this limit, the excess is charged to expense and reflected as additional accumulated DD&A.

Asset Retirement Obligations ("ARO"). We have significant obligations to plug and abandon natural gas and crude oil wells and related equipment at the end of oil and gas production operations. We record the fair value of a liability for an ARO in the period in which it is incurred and a corresponding increase in the carrying amount of the related asset. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense using the units of production method. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense in the Consolidated Statement of Operations.

Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. We use the present value of estimated cash flows related to the ARO to determine the fair value. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Income Taxes. In accordance with SFAS No. 109, *Accounting for Income Taxes*, we recognize deferred tax assets and liabilities for the future tax consequences of temporary differences between the carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates applicable to the years in which those differences are expected to be settled. The effect on deferred tax assets and liabilities of a change in tax rates under SFAS No. 109 is recognized in net income in the period that includes the enactment date.

Effective April 1, 2007, we adopted Financial Accounting Standards Bulletin ("FASB") Interpretation No. 48, Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109 ("FIN 48"), which clarifies the financial statement recognition and disclosure requirements for uncertain tax positions taken or expected to be taken in a tax return. Any interest and penalties related to uncertain tax positions are recorded as interest expense and general and administrative expense, respectively. At the time of adoption and as of March 31, 2008, we did not have any uncertain tax positions.

Revenue Recognition and Gas Balancing. Oil and gas sales and resulting receivables are recognized when the product is delivered to the purchaser and title has transferred. Sales are to credit-worthy energy purchasers with payments generally received within 60 days of transportation from the well site. We have historically had little, if any, uncollectible oil and gas receivables; therefore, an allowance for uncollectible accounts is not required. Gas imbalances are accounted for under the sales method whereby revenues are recognized based on production sold. A liability is recorded when our excess takes of natural gas volumes exceeds our estimated remaining recoverable reserves (over produced). No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production (under produced). We have no significant gas imbalances.

Income Per Common Share. Basic net income per share is computed by dividing net income by the weighted average number of shares outstanding during the period. Diluted net income per share is computed by dividing net income by the weighted average number of common shares and dilutive potential common shares (stock options) outstanding during the period. In periods where losses are reported, the weighted-average number of common shares outstanding excludes potential common shares, because their inclusion would be anti-dilutive.

The following is a reconciliation of the number of shares used in the calculation of basic income per share and diluted income per share for the periods ended March 31:

	2008	2007	2006
Weighted average number of common shares outstanding, basic	1,767,777	1,761,344	1,733,890
Incremental shares from the assumed exercise of dilutive stock options	5,272	58,625	93,136
Dilutive potential common shares	1,773,049	1,819,969	1,827,026

For the year ended March 31, 2008, potential common shares of 240,000, relating to stock options, were excluded in the computation of diluted net earnings per share because the exercise price of the options was greater than the average market price of the common shares and, therefore, the effect would be anti-dilutive. During the year ending March 31, 2007, 135,000 shares were excluded from the diluted net earnings per share calculations. For the year ended March 31, 2006, no anti-dilutive shares relating to stock options were excluded from the calculation. Anti-dilutive stock options have a weighted average exercise price of $6.49 at March 31, 2008.

Other Property and Equipment. Provisions for depreciation of office furniture and equipment are computed on the straight-line method based on estimated useful lives of five to ten years.

Stock-based Compensation. Prior to April 1, 2006 we accounted for employee stock-based compensation using the intrinsic value method in accordance with APB 25. Under APB 25, if the exercise price of employee stock options equaled the market price of the underlying stock on the grant date, no compensation expense was recorded. Effective the first quarter of fiscal 2007 (the quarter beginning April 2006), we adopted SFAS 123(R) using the modified prospective method which requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. For all unvested options outstanding as of April 1, 2006, the previously measured but unrecognized compensation expense based on the fair value at the original grant date will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to April 1, 2006, compensation expense based on the fair value at the date of grant or modification will be recognized in our financial statements over the vesting period. We recognize the fair value of stock-based compensation awards as wages in the Consolidated Statements of Operations based on a graded-vesting schedule over the vesting period. We utilize the Binomial option pricing model to measure the fair value of stock options. The adoption of SFAS 123(R) does not require restatement of previously issued financial statements.

Financial Instruments. Cash and money market funds, stated at cost, are available upon demand and approximate fair value. Interest rates associated with our long-term debt are linked to current market rates. As a result, management believes that the carrying amount approximates the fair value of our credit facilities. All financial instruments are held for purposes other than trading.

Recent Accounting Pronouncements. In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"), which provides guidance for using fair value to measure assets and liabilities. The pronouncement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, the FASB having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurement. SFAS 157, as originally issued, was effective for fiscal years beginning after November 15, 2007. However, in February 2008, the FASB issued FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157,* which provides a one year delay of the effective date of FAS 157 as it relates to nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). SFAS 157 as it relates to financial assets and liabilities will be effective as of the beginning of our 2009 fiscal year. Management is currently evaluating the impact of SFAS 157 on our financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Liabilities - Including an amendment of FASB Statement No. 115* ("SFAS 159"). SFAS 159 permits entities to choose to measure certain financial assets and liabilities at fair value. Unrealized gains and losses, arising subsequent to adoption, are reported in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We do not anticipate that the adoption of SFAS 159 will have a material effect on our consolidated financial statements.

3. Long-Term Debt

We have a revolving credit agreement with Bank of America, N.A. ("Bank"), which provides for a credit facility of $5,000,000, subject to a borrowing base determination. On September 26, 2007, the borrowing base was redetermined and set at $4,225,000 bearing interest at prime rate per annum with a maturity date of October 31, 2009. As of March 31, 2008, the balance outstanding under this agreement was $2,600,000 compared to $700,000 at March 31, 2007. Availability of this line of credit at March 31, 2008 was $1,625,000. No principal payments are anticipated to be required through March 31, 2009 based on the revised borrowing base. Two letters of credit for $50,000 each, in lieu of a plugging bond covering the properties we operate are outstanding under the facility, one with the Texas Railroad Commission and one with the State of New Mexico. The borrowing base is subject to redetermination on or about August 1 of each year. Amounts borrowed under this agreement are collateralized by the common stock of our wholly owned subsidiary, Forman Energy Corporation, and substantially all oil and gas properties. Interest under this agreement is payable monthly at prime rate (5.25% and 8.25% at March 31, 2008 and 2007, respectively). This agreement generally restricts our ability to transfer assets or control of the Company, incur debt, extend credit, change the nature of our business, substantially change management personnel, or pay cash dividends.

4. Asset Retirement Obligations

Our asset retirement obligations relate to the plugging of wells, the removal of facilities and equipment, and site restoration on oil and gas properties. SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset.

The following table provides a rollforward of the asset retirement obligations for the fiscal years ended March 31, 2008 and 2007:

	2008	2007
Carrying amount of asset retirement obligations as of April 1	$ 400,584	$ 372,956
Liabilities incurred	36,729	46,355
Liabilities settled	(38,786)	(42,784)
Accretion expense	26,262	24,057
Carrying amount of asset retirement obligations as of March 31	424,789	400,584
Less: current portion	50,000	50,000
Non-current asset retirement obligation	$ 374,789	$ 350,584

The asset retirement obligation is included on the consolidated balance sheets with the current portion being included in the accounts payable and accrued expenses.

5. Income Taxes

Significant components of net deferred tax assets (liabilities) at March 31 are as follows:

	2008	2007
Deferred tax assets:		
Percentage depletion carryforwards	$ 760,299	$ 667,423
Deferred stock-based compensation	42,226	39,876
Asset retirement obligation	131,685	124,182
Net operating loss	36,445	60,655
Other	3,168	3,871
	973,823	896,007
Deferred tax liabilities:		
Excess financial accounting bases over tax bases of property and equipment	(2,170,103)	(1,874,693)
Net deferred tax liabilities	$ (1,196,280)	$ (978,686)

As of March 31, 2008, we have statutory depletion carryforwards of approximately $2,453,000, which do not expire.

At March 31, 2008, we had a net operating loss carryforward for regular income tax reporting purposes of approximately $118,000, which will begin expiring in 2021. Our ability to use some of our net operating loss carryforwards and certain other tax attributes to reduce current and future U.S. federal taxable income is subject to limitations under the Internal Revenue Code.

A reconciliation of the provision for income taxes to income taxes computed using the federal statutory rate for years ended March 31 follows:

	2008	2007	2006
Tax expense at statutory rate	$ 316,621	$ 197,314	$ 360,721
Depletion in excess of basis	(93,000)	(99,200)	(10,806)
Effect of graduated rates	(27,937)	(17,410)	(31,828)
Revision of prior year estimates	7,487	(123,443)	(46,099)
Permanent differences	14,423	14,689	-
Other	-	-	152
	$ 217,594	$ (28,050)	$ 272,140
Effective tax rate	23%	(5%)	26%

6. Investment in GazTex, LLC

Our long-term asset consists of an investment in GazTex, LLC, a Russian company owned 50% by OBTX, LLC, accounted for by the equity method. OBTX, LLC is a Delaware limited liability company in which from January 16, 2007, Mexco owned 100% of the interest. There has not been any activity for the year ended March 31, 2008. In May 2008, we dissolved GazTex, LLC and received our initial cash investment less related fees and expenses for a net amount of $18,700.

7. Major Customers

Currently, we operate exclusively within the United States and our revenues and operating income are derived predominately from the oil and gas industry. Oil and gas production is sold to various purchasers and the receivables are unsecured. Historically, we have not experienced significant credit losses on our oil and gas accounts and management is of the opinion that significant credit risk does not exist. Management is of the opinion that the loss of any one purchaser would not have an adverse effect on our ability to sell our oil and gas production.

In fiscal 2008, Chesapeake Operating accounted for 14% and Conoco Phillips accounted for 13% of our total revenues. In fiscal 2007 and 2006, Southern Union Gas Services accounted for 12% and 16%, respectively, of revenues. At March 31, 2008, accounts receivable from Chesapeake Operating and Conoco Phillips were approximately 37% and 4%, respectively, of oil and gas accounts receivable.

8. Oil and Gas Costs

The costs related to our oil and gas activities were incurred as follows for the year ended March 31:

	2008	2007	2006
Property acquisition costs:			
Proved	$ 1,952,171	$ 603,271	$ 171,593
Unproved	-	-	29,592
Exploration	820,436	24,493	96,936
Development	685,043	953,271	335,122
Capitalized asset retirement obligations	36,729	46,355	2,851
Total costs incurred for oil and gas properties	$ 3,494,379	$ 1,627,390	$ 636,094

We had the following aggregate capitalized costs relating to our oil and gas property activities at March 31:

	2008	2007	2006
Proved oil and gas properties	$ 23,770,996	$ 20,355,944	$ 18,655,627
Unproved oil and gas properties:			
subject to amortization	170,487	170,487	170,487
not subject to amortization	-	-	121,418
	23,941,483	20,526,431	18,947,532
Less accumulated depreciation,			
depletion, and amortization	11,974,477	11,202,369	10,554,659
	$ 11,967,006	$ 9,324,062	$ 8,392,873

Depreciation, depletion, and amortization amounted to $1.60, $1.47 and $1.39 per equivalent mcf of production for the years ended March 31, 2008, 2007, and 2006, respectively.

9. Stockholders' Equity

In June 2006, the board of directors authorized the use of up to $250,000 in addition to a prior authorization of $250,000 to repurchase shares of our common stock for the treasury account. Throughout fiscal 2007, we repurchased 30,000 shares at an aggregate cost of $183,309, and during fiscal 2008, we repurchased 24,475 shares at an aggregate cost of $119,093.

10. Stock Options

We adopted an employee incentive stock plan effective September 15, 1997. Under the plan, 350,000 shares are available for distribution. Awards, granted at the discretion of the compensation committee of the board of directors, include stock options or restricted stock. Stock options may be an incentive stock option or a nonqualified stock option. Options to purchase common stock under the plan are granted at the fair market value of the common stock at the date of grant, become exercisable to the extent of 25% of the shares optioned on each of four anniversaries of the date of grant, expire ten years from the date of grant and are subject to forfeiture if employment terminates. Restricted stock awards may be granted with a condition to attain a specified goal. The purchase price will be at least $5.00 per share of restricted stock. The awards of restricted stock must be accepted within 60 days and will vest as determined by agreement. Holders of restricted stock have all rights of a shareholder of the Company.

In September 2004, the board of directors of the Company adopted the 2004 Incentive Stock Plan to replace, modify and extend the termination date of the September 15, 1997 stock plan to September 14, 2009. This new plan provides for the award of stock options up to 375,000 shares of which 125,000 may be the subject of stock grants without restrictions and without payment by the recipient and stock awards of up to 125,000 shares with restrictions including payment for the shares and employment of not less than three years from the date of the award. The terms of the stock options are similar to those of the existing stock option plan except that the term of the Plan is five years from the date of its adoption.

In accordance with both Plans, upon the exercise of stock options, new shares will be issued. The Company can repurchase shares exercised under these Plans. Through the year ended March 31, 2007, we repurchased 20,000 shares for the treasury at an aggregate cost of $127,300. We did not repurchase any exercised shares for the treasury during the year ended March 31, 2008. The Plan also provides for the granting of stock awards. During fiscal 2007, we granted a stock award of 2,000 shares to a director of the Company. No stock awards were granted during fiscal 2008.

The following pro forma information presents net income and earnings per share for the year ended March 31, 2006 as if the stock-based compensation had been recorded at the estimated fair value of stock awards on the grant date. The fair value of stock options issued was estimated at the date of grant using the Binomial option pricing model.

		2006
Net income, as reported	$	788,805
Deduct: Stock-based employee compensation expense determined under fair value based method (SFAS 123), net of tax		(72,078)
Net income, pro forma	$	716,727
Basic income per share:		
As reported	$	0.45
Pro forma	$	0.41
Diluted income per share:		
As reported	$	0.43
Pro forma	$	0.39

The adoption of SFAS 123(R) in the first quarter of fiscal year 2007 resulted in prospective changes in the accounting for stock-based compensation awards including recording stock-based compensation expense related to stock options that became vested during each quarter on a prospective basis. If an exercise and sale of vested options results in a disqualifying disposition, a tax deduction for the Company occurs. The excess tax benefit from the disqualifying disposition of options is reflected both in cash flows from operating activities and cash flows from financing activities in the Consolidated Statements of Cash Flows.

We recognized compensation expense of $85,877, $126,454 and $19,496 in general and administrative expense in the Consolidated Statements of Operations for fiscal 2008, 2007 and 2006, respectively. The total cost related to non-vested awards not yet recognized at March 31, 2008 totals $88,929, which is expected to be recognized over a weighted average of 2.66 years.

In periods ending prior to April 1, 2006 the income tax benefits from the exercise of stock options were classified as net cash provided by operating activities pursuant to Emerging Issues Task Force Issue No. 00-15. However, for periods beginning after April 1, 2006 pursuant to SFAS 123(R), the excess tax benefits are required to be reported in net cash provided by financing activities. For the year ended March 31, 2008, excess tax benefits from disqualifying dispositions of options of $1,100 were reflected in both cash flows from operating activities and cash flows from financing activities in the Consolidated Statements of Cash Flows.

The fair value of each stock option is estimated on the date of grant using the Binomial valuation model. Expected volatilities are based on historical volatility of the Company’s stock over the expected term of 60 months and other factors. We use historical data to estimate option exercise and employee termination within the valuation model. The expected term of options granted is derived from the output of the option valuation model and represents the period of time that options granted are expected to be outstanding. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. As the Company has never declared dividends, no dividend yield is used in the calculation. Actual value realized, if any, is dependent on the future performance of the Company's common stock and overall stock market conditions. There is no assurance the value realized by an optionee will be at or near the value estimated by the Binomial model.

Included in the following table is a summary of the grant-date fair value of stock options granted and the related assumptions used in the Binomial models for stock options granted in fiscal 2008 and 2007 (no options were granted in fiscal 2006). All such amounts represent the weighted average amounts for each period.

	For the year ended March 31,		
	2008	2007	2006
Grant-date fair value	$ 2.20	$ 5.15	-
Volatility factor	56.06%	71.46%	-
Dividend yield	-	-	-
Risk-free interest rate	3.54%	5.07%	-
Expected term (in years)	5	5	-

During the year ended March 31, 2008 and 2007, stock options covering 25,000 and 35,000 shares, respectively, were granted. Stock options covering 1,000 shares were exercised during the year ended March 31, 2008 and 61,800 shares were exercised during the year ended March 31, 2007.

Prior to April 1, 2007, notice of termination was sent to a consultant and his remaining 30,000 vested options forfeited on June 20, 2007. During the second quarter of fiscal 2008 we received notice of resignation from an employee and her remaining 5,250 vested and 3,750 unvested options forfeited on November 30, 2007. During the year ended March 31, 2007, 18,200 stock options were forfeited due to the termination of consulting agreements with two of our consultants. However, these are all isolated events which we do not expect in the future. We have assumed no options will be forfeited before vesting due to the limited number of employees at the executive and senior management level who receive stock options, past employment history and current stock price projections.

The following table is a summary of activity of stock options for the year ended March 31, 2007 and 2008:

	Number of Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contract Life in Years	Aggregate Intrinsic Value
Outstanding at March 31, 2006	350,000	$ 5.88		
Granted	35,000	8.24		
Exercised	(61,800)	4.69		
Forfeited or Expired	(18,200)	6.75		
Outstanding at March 31, 2007	305,000	$ 6.35	4.01	$ (366,350)
Granted	25,000	4.35		
Exercised	(1,000)	4.00		
Forfeited or Expired	(39,000)	7.31		
Outstanding at March 31, 2008	290,000	$ 6.06	3.30	$ (535,750)
Vested at March 31, 2008	235,000	$ 6.02	3.11	$ (424,225)
Exercisable at March 31, 2008	235,000	$ 6.02	3.11	$ (424,225)

Outstanding options at March 31, 2008 expire between April 2008 and July 2014 and have exercise prices ranging from $4.00 to $8.24.

Other information pertaining to option activity was as follows during the year ended March 31:

	2008	2007	2006
Weighted average grant-date fair value of stock options granted (per	$ 4.35	$ 5.15	$ —

share)						
Total fair value of options vested	$	124,300	$	137,925	$	147,575
Total intrinsic value of options exercised	$	1,100	$	110,019	$	42,500

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Cash received from option exercise under all share-based payment arrangements for the years ended March 31, 2008, 2007 and 2006, was $4,000, $197,150 and $52,500, respectively.

The following table summarizes information about options outstanding at March 31, 2008:

Range of Exercise Prices	Number of Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value
$4.00 - 5.24	75,000	$ 4.12		
5.25 - 6.49	85,000	5.67		
6.50 - 7.74	80,000	7.05		
7.75 - 8.24	50,000	8.04		
$4.00 - 8.24	290,000	$ 6.06	3.30	$ (535,750)

The following table summarizes information about options exercisable at March 31, 2008:

Range of Exercise Prices	Number Exercisable	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value
$4.00 - 5.24	50,000	$ 4.00	
5.25 - 6.49	82,500	5.65	
6.50 - 7.74	75,000	7.07	
7.75 - 8.24	27,500	7.88	
$4.00 - 8.24	235,000	$ 6.02	$ (424,225)

11. Related Party Transactions

Related party transactions with the majority stockholder for the years ended March 31, 2008, 2007 and 2006 relate to shared office expenditures. The total billed to the stockholder for years ended March 31, 2008, 2007 and 2006 was $36,368, $44,194 and $40,805, respectively.

A Family Limited Partnership of Thomas Craddick, a member of the board of directors and Company employee, received from the Company a finders fee in kind, equal to 2.5% of the total interest purchased of the mineral acres in the Newark East Field in Tarrant County, Texas.

On April 1, 2007, Jeff Smith, a member of the board of directors entered into a consulting agreement with the Company to provide geological consulting services for a fee of $10,000 per month. As part of this agreement, Mr. Smith received from the Company a 0.5% overriding interest in our well in Loving County, Texas. Mr. Smith invested his personal funds in a working interest (2.5% before payout and 1.875% after payout) and also received from the Company a 0.5% overriding interest in our well in Reeves County, Texas.

12. Oil and Gas Reserve Data (Unaudited)

The estimates of our proved oil and gas reserves, which are located entirely within the United States, were prepared in accordance with the guidelines established by the SEC and FASB. These guidelines require that reserve estimates be prepared under existing economic and operating conditions at year-end, with no provision for price and cost escalators, except by contractual agreement. The estimates as of March 31, 2008, 2007, and 2006 are based on evaluations prepared by Joe C. Neal and Associates, Petroleum Consultants.

Management emphasizes that reserve estimates are inherently imprecise and are expected to change as new information becomes available and as economic conditions in the industry change. The following estimates of proved reserves quantities and related standardized measure of discounted net cash flow are estimates only, and do not purport to reflect realizable values or fair market values our reserves.

Changes in Proved Reserve Quantities:

	2008		2007		2006	
	Bbls	Mcf	Bbls	Mcf	Bbls	Mcf
Proved reserves, beginning of year	220,000	6,905,000	183,000	6,697,000	151,000	7,327,000
Revision of previous estimates	(11,000)	109,000	6,000	212,000	47,000	(292,000)
Purchase of minerals in place	-	584,000	33,000	199,000	-	36,000
Extensions and discoveries	26,000	638,000	15,000	136,000	2,000	1,000
Sales of minerals in place	-	-	-	-	-	(5,000)
Production	(18,000)	(379,000)	(17,000)	(339,000)	(17,000)	(370,000)
Proved reserves, end of year	217,000	7,857,000	220,000	6,905,000	183,000	6,697,000

Proved Developed Reserves:

Beginning of year	111,000	3,968,000	87,000	3,891,000	108,000	4,597,000
End of year	122,000	5,050,000	111,000	3,968,000	87,000	3,891,000

The following is a standardized measure of the discounted net future cash flows and changes applicable to proved oil and gas reserves required by *SFAS No. 69, Disclosures about Oil and Gas Producing Activitites* (SFAS No. 69). The future cash flows are based on estimated oil and gas reserves utilizing prices and costs in effect as of year end, discounted at 10% per year and assuming continuation of existing economic conditions.

The year ended weighted average oil price utilized in the computation of future cash inflows was $96.61, $59.61, and $58.55 per barrel at March 31, 2008, 2007 and 2006, respectively. The year ended weighted average gas price utilized in the computation of future cash inflows was $8.70, $6.85 and $6.73 per mcf at March 31, 2008, 2007 and 2006, respectively. Future cash flows are reduced by estimated future costs to develop and to produce the proved reserves assuming continuation of existing economic conditions.

The standardized measure of discounted future net cash flows, in management's opinion, should be examined with caution. The basis for this table is the reserve studies prepared by independent petroleum engineering consultants, which contain imprecise estimates of quantities and rates of production of reserves. Revisions of previous year estimates can have a significant impact on these results. Also, exploration costs in one year may lead to significant discoveries in later years and may significantly change previous estimates of proved reserves and their valuation. Therefore, the standardized measure of discounted future net cash flow is not necessarily indicative of the fair value of our proved oil and gas properties.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves:

	March 31		
	2008	2007	2006
Future cash inflows	$ 89,327,000	$ 60,428,000	$ 55,804,000
Future production and development costs	(15,891,000)	(13,181,000)	(13,939,000)
Future income taxes (a)	(15,086,000)	(10,769,000)	(9,646,000)

Future net cash flows		58,350,000		36,478,000		32,219,000
Annual 10% discount for estimated timing of cash flows		(25,852,000)		(16,271,000)		(14,295,000)
Standardized measure of discounted future net cash flows	$	32,498,000	$	20,207,000	$	17,924,000

(a) Future income taxes are computed using effective tax rates on future net cash flows before income taxes less the tax bases of the oil and gas properties and effects of statutory depletion.

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Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	March 31 2008	2007	2006
Sales of oil and gas produced, net of production costs	$ (2,648,000)	$ (2,099,000)	$ (2,873,000)
Net changes in price and production costs	9,027,000	1,835,000	3,985,000
Changes in previously estimated development costs	295,000	313,000	701,000
Revisions of quantity estimates	(121,000)	825,000	428,000
Net change due to purchases and sales of minerals in place	2,343,000	1,362,000	74,000
Extensions and discoveries, less related costs	5,025,000	561,000	45,000
Net change in income taxes	(2,437,000)	(599,000)	(579,000)
Accretion of discount	2,617,000	2,329,000	2,095,000
Changes in timing of estimated cash flows and other	(1,810,000)	(2,244,000)	(2,111,000)
Changes in standardized measure	12,291,000	2,283,000	1,765,000
Standardized measure, beginning of year	20,207,000	17,924,000	16,159,000
Standardized measure, end of year	$ 32,498,000	$ 20,207,000	$ 17,924,000

13. Selected Quarterly Financial Data (Unaudited)

	FISCAL 2008 4TH QTR	3RD QTR	2ND QTR	1ST QTR
Oil and gas revenue	$ 1,245,653	$ 952,211	$ 839,947	$ 850,144
Operating profit	613,742	345,203	4,344	68,148
Net income (loss)	466,480	221,114	(8,756)	34,806
Net income per share-basic	0.27	0.13	-	0.02
Net income per share-diluted	0.27	0.12	-	0.02

	FISCAL 2007 4TH QTR	3RD QTR	2ND QTR	1ST QTR
Oil and gas revenue	$ 755,184	$ 663,031	$ 773,698	$ 777,412
Operating profit	110,106	109,906	229,920	144,944
Net income	183,481	67,080	130,534	227,290
Net income per share-basic	0.11	0.04	0.07	0.13
Net income per share-diluted	0.10	0.04	0.07	0.12

INDEX TO EXHIBITS

Exhibit Number	
3.1*	Articles of Incorporation.
3.2***	Bylaws.
10.1**	Stock Option Plan.
10.2*	Bank Line of Credit.
10.3****	2004 Incentive Stock Option.
14.1*****	Code of Business Conduct and Ethics.
21*	Subsidiaries of the Company.
31.1	Certification of the Chief Executive Officer of the Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer of the Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Incorporated by reference to the Company's Annual Report on Form 10-K dated June 24, 1998.
** Incorporated by reference to the Amendment to Schedule 14C Information Statement filed on August 13, 1998.
*** Filed with the Company's Annual Report on Form 10-K dated June 29, 2004.
**** Filed with the Company's Proxy Statement filed July 9, 2004.
***** Filed with the Company's Quarterly Report on Form 10-Q filed on November 15, 2004.