MEXCO ENERGY CORP
Form 10-K
June 25, 2009

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

FORM 10-K

[√] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended March 31, 2009

[ ] 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 (State or other jurisdiction of incorporation or organization)	84-0627918 (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 [ ] No [√]

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

Indicate by check-mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 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 [√] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [ ] No [ ]

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 [ ]	Accelerated Filer [ ]	Non-Accelerated Filer [ ]	Smaller Reporting Company [Ö]
	(Do not check if a smaller reporting company)		

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

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of September 30, 2008 (the last business day of the Registrant’s most recently completed second quarter) was $11,026,273 based on Mexco Energy Corporation’s closing common stock price of $17.01 per share on that date as reported by the American Stock Exchange.

There were 1,878,616 shares of the registrant’s common stock, $.50 par value, outstanding as of June 23, 2009.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant’s Proxy Statement relating to the 2009 Annual Meeting of Shareholders to be held on September 15, 2009, 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 120 days after March 31, 2009, the end of the fiscal year covered by this report.

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This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended, (the "Exchange Act") 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", "anticipate", "intend", "budget", "plan", "forecast", "predict" an expressions. Forward-looking statements appear 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 Ener 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. Since its date of formation, OBTX, LLC has been included in the consolidated financial statements. OBTX, LLC was dissolved in March 2009. OBTX, LLC owned 50% of GazTex, LLC, a limited liability company which was dissolved in May 2008. Prior to dissolution, GazTex, LLC had no operations other than evaluation activities on properties in Russia.

Our total estimated proved reserves at March 31, 2009 were approximately 9.477 Bcf of natural gas and 207,000 barrels of oil and natural gas liquids, and our estimated present value of proved reserves was approximately $14.3 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 2009, we added proved reserves of 1,322,000 Mcfe through extensions and discoveries, added 886,000 Mcfe through acquisitions and had downward revisions of previous estimates of 4,000 Mcfe.

Nicholas C. Taylor beneficially owns approximately 47% 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 focus primarily on acquiring natural gas reserves. We especially seek to acquire proved reserves that fit well with existing operations or in areas where the Company has established production. Acquisitions preferably will contain most of their value in producing wells, behind pipe reserves and 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 to acquire reserves without assuming significant price and production risks. We actively search 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 2010.

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, 2009, gas reserves constituted approximately 88% of our total proved reserves and approximately 71% of our revenues for fiscal 2009. Revenues from oil and gas royalty interests accounted for approximately 42% of our revenues for fiscal 2009.

Newark East (Barnett Shale) Gas Field properties, encompassing 5,874 gross acres, 70 net acres, 108 gross producing wells and .76 net wells in Denton, Johnson, Tarrant and Wise Counties, Texas, account for approximately 22% of our discounted future net cash flows from proved reserves as of March 31, 2009. For fiscal 2009, this field, consisting of royalty interests, accounted for approximately $1,207,000 or 25% of our total revenues and approximately $63,000 or 5% of our total production costs. These costs were ad valorem and production taxes. During fiscal 2009, we purchased royalty interests totaling approximately $1,700,000 in Johnson and Tarrant Counties, which have materially increased our earnings.

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 26% of our discounted future net cash flows from proved reserves as of March 31, 2009. This is a multi-pay area where most of the leases have potential reserves in two zones. Of these discounted future net cash flows from proved reserves, approximately 15% are attributable to proven undeveloped reserves which will be developed through re-entry of existing wells and new drilling. For fiscal 2009, these properties accounted for approximately $672,000 or 14% of our total revenues and approximately $180,000 or 15% of our total production costs.

Gomez Gas Field properties, encompassing 13,847 gross acres, 72 net acres, 28 gross wells and .13 net wells in Pecos County, Texas, account for approximately 6% of our discounted future net cash flows from proved reserves as of March 31, 2009. For fiscal 2009, these properties accounted for approximately $302,000 or 6% of our total revenues and approximately $32,000 or 3% of our total production costs. All of these properties, except for one, are royalty interests.

Viejos Gas Field properties, encompassing 2,583 gross acres, 157 net acres, 17 gross wells and 1.19 net wells in Pecos County, Texas, account for approximately 1% of our discounted future net cash flows from proved reserves as of

March 31, 2009. For fiscal 2009, this field accounted for approximately $174,000 or 4% of our total revenues and approximately $47,000 or 4% of our total production costs.

We own interests in and operate 18 producing wells, one shut-in well and one salt water disposal well. We own partial interests in an additional 2,324 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)
2009	17,065	542,099
2008	17,504	379,048
2007	16,738	339,174
2006	17,118	370,069
2005	17,372	404,133

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

	2009	2008	2007
Chesapeake Operating	22%	14%	-
Conoco Phillips	10%	13%	-
	-	-	12%

Southern Union Gas
Services

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; it may also subject us to greater competition, 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 following is some of the existing laws, rules and regulations to which our business is subject:

The 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.

The federal Clean Air Act ("CAA"), and comparable state and local requirements, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. The EPA and states have developed, and continue to develop, regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirement of the federal CAA and associated state laws and regulations. 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.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases. The U.S. President has expressed support for legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations.

Also, as a result of the United States Supreme Court's decision on April 2, 2007 in Massachusetts, et al. v. EPA, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in Massachusetts that greenhouse gases, including carbon dioxide, fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, the EPA released an "Advance Notice of Proposed Rulemaking" regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court's decision in Massachusetts. In the notice, the EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions, which could have an adverse effect on our business and the demand for our products.

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.

The Federal Water Pollution Control Act ("Clean Water Act") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of produced water and sand and other substances related to the oil and gas industry is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. 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.

We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, however we cannot assure you that the passage or application of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operation. We did not incur any material capital expenditures for remediation or pollution control activities for the year ended March 31, 2009. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during fiscal 2010.

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, 2009.

Name	Age	Position
Nicholas C. Taylor	71	President and Chief Executive Officer
Donna Gail Yanko	64	Vice President and Secretary
Tamala L. McComic	40	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 in 1990. Mrs. Yanko served as a director of the Company from 1990 to 2008.

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, 2009, 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 services such as drilling and production operations as well as the services of independent consultants to perform various professional services particularly in the areas of geological and curative work. 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 Avenue, 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.

RISKS RELATED TO OUR BUSINESS

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.

Approximately 38 percent of our total estimated net proved reserves at March 31, 2009 were undeveloped, and those reserves may not ultimately be developed.

Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. If we choose not to spend the capital to develop these reserves, or if we are not able to successfully develop these reserves, we will be required to write-off these reserves. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our common stock.

Our exploration and development drilling may not result in commercially productive reserves.

New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. Drilling for crude oil and natural gas often involves unprofitable efforts, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

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. 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.

We may be unable to make attractive acquisitions or successfully integrate acquired companies, and any inability to do so may disrupt our business and hinder our ability to grow.

We may not be able to identify attractive acquisitions or opportunities that complement or expand our current business. Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms. Our credit facility imposes certain direct limitations on our ability to enter into mergers or combination transactions involving our company. Our credit facility also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses. If we desire to engage in an acquisition that is otherwise prohibited by our credit facility, we will be required to seek the consent of our lenders in accordance with the requirements of the facility, which consent may be withheld by the lenders under our credit facility in their discretion. Furthermore, given the current situation in the credit markets, many lenders are reluctant to provide consents in any circumstances, including to allow accretive transactions. In addition, we could have difficulty integrating acquired businesses successfully into our existing business which could result in our incurring unanticipated expenses and losses and adversely affecting our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Failure to comply with covenants under our debt agreement could adversely impact our financial condition and results of operations.

Our revolving credit facility agreement requires us to comply with certain customary covenants including limitations on disposition of assets, mergers and reorganizations. We are also obligated to meet certain financial covenants. For example, our revolving credit facility requires us to, among other things, maintain tangible net worth in accordance with computational guidelines contained in the related loan agreement. If we fail to meet any of these loan covenants, the lender under the revolving credit facility could accelerate the indebtedness and seek to foreclose on the pledged assets.

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.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

A substantial amount of our business activities are conducted through joint operating or other agreements under which we own working and royalty interests in natural gas and oil properties in which we do not operate. As a result, we have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. The failure of an operator of our wells to adequately perform operations could reduce our revenues and production.

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.

The loss of our chief executive officer or other key personnel could adversely impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, upon the continued services of our Chief Executive Officer, Nicholas C. Taylor, our Chief Financial Officer, Tamala L. McComic, and other key personnel, who have extensive experience and expertise in evaluating and analyzing producing oil and gas properties and drilling prospects, maximizing production from oil and gas properties and developing and executing acquisitions and financing. We do not have key-man insurance on the lives of Mr. Taylor and Ms. McComic. The unexpected loss of the services of one or more of these individuals could, therefore, significantly and adversely affect our operations. Competition for qualified individuals is intense and we may be unable to find or attract qualified replacements for our officers and key employees on acceptable terms.

We may be affected by one substantial shareholder.

Nicholas C. Taylor beneficially owns approximately 47% 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. The retirement, incapacity or death of Mr. Taylor, or any change in the power to vote shares beneficially owned by Mr. Taylor, could result in negative market or industry perception and could have an adverse effect on our business.

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.

Increases in taxes on energy sources may adversely affect the company's operations.

Federal, state and local governments which have jurisdiction in areas where the company operates impose taxes on the oil and natural gas products sold. Historically, there has been an on-going consideration by federal, state and local officials concerning a variety of energy tax proposals. Such matters are beyond the company's ability to accurately predict or control.

The continuing crisis in U.S. and world financial and securities markets could have a material adverse effect on our business and operations.

Our operations are affected by local, national and worldwide economic conditions. Global financial markets and economic conditions have been and will likely continue to be, disrupted and volatile. The debt and equity capital markets have become uncertain making it difficult to obtain funding. With the current turbulent credit markets, lenders may become more restrictive in their lending practices, lower the borrowing base available or be unable or unwilling to fund their commitments, which would limit our access to capital to fund our capital expenditures and operations. Lenders may be reluctant to lend without receiving higher fees and rates. Our Credit Facility bears floating interest rates based on the London Interbank Offer Rate (“LIBOR”). As banks have been reluctant to lend to each other to avoid risk, LIBOR has increased to unprecedented spread levels. This causes higher interest expense on borrowings. The economic slowdown has led and could continue to lead to lower demand for oil and natural gas by individuals and industries, which in turn could result in even lower prices for the oil and natural gas we sell, thereby adversely resulting in declining production, lower revenues, and possibly losses and negative cash flow.

RISKS RELATED TO OUR COMMON STOCK

We have not and do not anticipate paying any cash dividends on our common stock in the foreseeable future.

We have paid no cash dividends on our common stock to date and it is not anticipated that any will be paid to holders of our common stock in the foreseeable future. The terms of our existing credit facility restricts the payment of dividends without the prior written consent of the lenders. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Stockholders must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

We may issue additional shares of common stock in the future, which could cause dilution to all shareholders.

We may seek to raise additional equity capital in the future. Any issuance of additional shares of our common stock will dilute the percentage ownership interest of all shareholders and may dilute the book value per share of our common stock.

Control by our executive officers and directors may limit your ability to influence the outcome of matters requiring stockholder approval and could discourage our potential acquisition by third parties.

As of March 31, 2009, our executive officers and directors beneficially owned approximately 54% of our common stock. These stockholders, if acting together, would be able to influence significantly all matters requiring approval by our stockholders, including the election of our board of directors and the approval of mergers or other business combination transactions.

The price of our common stock has been volatile and could continue to fluctuate substantially.

Mexco common stock is traded on the American Stock Exchange. The market price of our common stock has been volatile and could fluctuate substantially due to fluctuations in commodity prices, variations in results of operations, legislative or regulatory changes, general trends in the industry, market conditions, and analysts' estimates and other events in the oil and gas oil industry.

We will continue to incur increased costs as a result of operating as a public company, and our management is required to devote substantial time to new compliance requirements.

As a public company we incur legal, accounting and other expenses under the Sarbanes-Oxley Act of 2002, together with rules implemented by the SEC and applicable market regulators. These rules impose various requirements on public companies, including requiring certain corporate governance practices. Our management and other personnel devote a substantial amount of time to these new compliance requirements. Moreover, these rules and regulations will increase our legal and financial compliance costs and make some activities more time-consuming and costly. In addition, the Sarbanes-Oxley Act states, among other things, that we are responsible for establishing and maintaining effective internal control over financial reporting. Internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with accounting principles generally accepted in the USA. Internal control over financial reporting includes maintaining records that in reasonable detail accurately and fairly reflect the Company's transactions; providing reasonable assurance that transactions are recorded as necessary for preparation of the financial statements; providing reasonable assurance that receipts and expenditures are made in accordance with management authorization; and providing reasonable assurance that unauthorized acquisition, use or disposition of the Company assets that could have a material effect on the financial statements would be prevented or detected on a timely basis.

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, 2009, we had interests in 2,342 gross (24 net) oil and gas wells and owned leasehold interests in approximately 278,706 gross (3,310 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, 2009, 2008 and 2007 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, 2009	2008	2007
Oil (Bbls):			
Proved developed – Producing	78,959	117,874	110,060
Proved developed – Non-producing	32,732	3,754	1,432
Proved undeveloped	95,694	95,599	108,263
Total	207,385	217,227	219,755
Natural gas (Mcf):			
Proved developed – Producing	4,326,857	3,954,269	2,892,964
Proved developed – Non-producing	1,662,641	1,096,174	1,075,376
Proved undeveloped	3,487,579	2,806,179	2,936,708
Total	9,477,077	7,856,622	6,905,048
Present value of estimated future net revenues before income taxes(PV-10) (1)	$ 14,348,450	$ 40,899,620	$ 26,172,460
Present value of future income tax discounted at 10%	(2,840,450)	(8,401,620)	(5,965,460)
Standardized measure of discounted future net cash flows (2)	$ 11,508,000	$ 32,498,000	$ 20,207,000

(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, 2009:

	Gross	Net
Oil	1,396	13
Gas	946	11
Total Productive Wells	2,342	24

The following table sets forth the approximate developed acreage in which we held a leasehold mineral or other interest as of March 31, 2009:

	Developed Acres	
	Gross	Net
Texas	141,602	2,901
Oklahoma	41,212	163
New Mexico	20,117	154
Louisiana	29,730	36
Kansas	8,520	24
North Dakota	24,919	21
Montana	7,868	5
Wyoming	3,298	5
Colorado	1,120	1
Arkansas	320	-
Total	278,706	3,310

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, 2009, 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,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	2	.28	4	.56	-	-
Nonproductive	-	-	1	.09	-	-
Total	2	.28	5	.65	-	-

Development Wells

Productive	12	.55	27	.42	47	.22
Nonproductive	-	-	1	.06	-	-
Total	12	.55	28	.48	47	.22

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,		
	2009	2008	2007
Oil (a):			
Production (Bbls)	17,065	17,504	16,738
Revenue	$ 1,403,076	$ 1,348,725	$ 995,557
Average Bbls per day	47	48	46
Average sales price per Bbl	$ 82.22	$ 77.05	$ 59.48
Gas (b):			
Production (Mcf)	542,099	379,048	339,174
Revenue	$ 3,473,551	$ 2,539,230	$ 1,973,768
Average Mcf per day	1,485	1,038	929
Average sales price per Mcf	$ 6.41	$ 6.70	$ 5.82
Production cost:			
Production cost	$ 1,195,584	$ 1,240,305	$ 870,778
Equivalent Mcf (c)	644,489	484,072	439,602
Production cost per equivalent Mcf	$ 1.86	$ 2.56	$ 1.98
Production cost per sales dollar	$ 0.25	$ 0.32	$ 0.29
Total oil and gas revenues	$ 4,876,627	$ 3,887,995	$ 2,969,325

(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 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, 2009.

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 bulletin board market under the symbol "MEXC". The registrar and transfer agent is Computershare Trust Company N.A., 250 Royall Street, Canton, Massachusetts, 02021 (Tel: 800-962-4284). As of March 31, 2009, we had approximately 1,300 shareholders of record and 1,962,616 shares issued.

PRICE RANGE OF COMMON STOCK

		High		Low
2009:				
April - June 2008 (1)	$	49.40	$	4.21
July - September 2008 (1)		37.56		17.01
October - December 2008 (1)		16.11		8.08
January - March 2009 (1)		13.88		5.32
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

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

On June 19, 2009, the closing price was $14.00.

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. There were no shares of our common stock repurchased for the treasury account during fiscal 2009.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

	Year Ended March 31,									
		2009		2008		2007		2006		2005
Statement of Operations:										
Operating revenues	$	4,925,993	$	3,899,408	$	2,971,717	$	3,719,643	$	2,969,826
Operating profit		1,778,955		1,031,437		594,876		1,114,966		924,230
Other income (expense)		(80,123)		(100,199)		(19,376)		(95,820)		(88,408)
Net income	$	1,170,570	$	713,644	$	608,385	$	788,805	$	577,527
Net income per share – basic	$	0.63	$	0.40	$	0.35	$	0.45	$	0.33
	$	0.61	$	0.40	$	0.33	$	0.43	$	0.32

Net income per share – diluted										
Weighted average shares outstanding – basic		1,846,394		1,767,777		1,761,344		1,733,890		1,734,726
Weighted average shares outstanding – diluted		1,934,235		1,773,049		1,819,969		1,827,026		1,801,167
Balance Sheet:										
Property and equipment, net	$	13,731,126	$	11,982,950	$	9,337,566	$	8,399,929	$	8,484,743
Total assets		14,508,880		13,202,659		9,958,980		8,978,324		9,303,149
Total debt		1,400,000		2,600,000		700,000		600,000		1,990,000
Stockholders’ equity		10,927,610		8,460,064		7,775,636		6,898,996		6,038,195
Cash Flow:										
Cash provided by operations	$	2,794,379	$	1,474,764	$	1,325,024	$	1,900,665	$	1,451,628

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Selected Quarterly Financial Data (Unaudited)

	FISCAL 2009			
	4TH QTR	3RD QTR	2ND QTR	1ST QTR
Oil and gas revenue	$ 700,578	$ 908,253	$ 1,595,209	$ 1,672,587
Operating profit (loss)	(52,505)	217,985	796,586	816,889
Net income (loss)	(10,835)	131,501	511,115	538,789
Net income (loss) per share-basic	(.01)	0.07	0.27	0.31
Net income (loss) per share-diluted	(.01)	0.07	0.26	0.29

	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

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. In the past two fiscal years, we have obtained additional financing for prospects by selling fractional working interests to industry partners at prices in excess of our cost.

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 2009, we primarily used cash provided by operations ($2,794,379) to fund oil and gas property acquisitions and development ($2,937,939). We had working capital of $221,989 as of March 31, 2009 compared to working capital of $627,674 as of March 31, 2008, a decrease of $405,685. This was mainly a result of a decrease in accounts receivable and cash and cash equivalents. The accounts receivable decrease was mainly a result of a decrease in oil and gas sales during the fourth quarter from a decrease in oil and gas prices.

During the third quarter of fiscal 2008, we acted as operator and drilled an exploratory well in Loving County, Texas which has been completed. We have acquired right-of-way, built a pipeline and commenced testing and sales of natural gas from this well. Our share of the costs incurred for this project through April 2009 for our 31.25% working interest is approximately $567,000.

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, 5 proven undeveloped well locations and an additional

6 potential drill sites in the Newark East (Barnett-Shale) Field of Tarrant County, Texas for approximately $429,000. This acreage now has 8 producing natural gas wells with an additional well currently being drilled. We subsequently purchased additional royalties in this acreage on March 31, 2009 for approximately $49,000.

Effective July 1, 2008, we purchased a well in Loving County, Texas which is capable of producing from the Lower Cherry Canyon section. We are acting as operator and have re-entered the well, tested one horizon as non-productive and tested the Bell Canyon, for which we are currently purchasing right-of-way for transmission and sales of natural gas. Our share of the costs for our 50.2% working interest through April 2009 is approximately $182,000.

In September 2008, we committed to participate in the drilling of a development well in Limestone County, Texas. This well has been completed and is currently producing. Costs incurred for this project through April 2009 are approximately $35,000.

In September 2008, we acted as operator and re-entered a well in Ward County, Texas to an approximate depth of 14,000 feet to test the upper and lower Pennsylvanian intervals. This well was recompleted, perforated, acid fraced and is currently being tested after completion of a pipeline for sales of natural gas. Costs incurred for this project through April 2009 for our 25.5% working interest are approximately $174,000. We also own a 2% overriding royalty interest in this well.

On October 16, 2008, we purchased interests in approximately 143 mineral acres amounting to an approximate 10% net royalty in three gas wells located in Johnson County, Texas for approximately $1,275,000. This property contains three (3) development wells in the Newark East (Barnett Shale) Field which were put on production in mid-November 2008. Approximately 28 of the 143 acres are outside of the drilling and spacing unit for these three wells and are also available for further development. A Family Limited Partnership of a director and employee of the Company received a finder's fee of 2.5% of the mineral interest purchased in lieu of a cash payment as disclosed in a report to the SEC on Form 8-K dated October 15, 2008.

We continue to focus our efforts on the acquisition of royalties in areas with significant development potential.

We are participating in other projects and are reviewing 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. During the second quarter of fiscal 2009, oil and gas prices began trending downward, while drilling, completion and operating costs remained high. The effect of declining product prices on our business is significant. Lower product prices reduce our cash flow from operations and diminish the present value of our oil and gas reserves. Lower product prices also offer us less incentive to assume the drilling risks that are inherent in our business. The volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, the West Texas Intermediate ("WTI") posted price for crude oil has ranged from a low of $30.28 per bbl in December 2008 to a high of $145.31 per bbl in July 2008. The Henry Hub Spot Market Price ("Henry Hub") for natural gas has ranged from a low of $3.58 per MMBtu in March 2009 to a high of $13.31 in July 2008 per MMBtu. On March 31, 2009 the WTI posted price for crude oil was $49.64 per bbl and the Henry Hub spot price for natural gas was $3.58 per MMBtu. 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 2009 Compared to Fiscal 2008

Net income increased from $713,644 for the year ended March 31, 2008 to $1,170,570 for the year ended March 31, 2009, an increase of 64%.

Oil and gas sales. Revenue from oil and gas sales increased 25% from $3,887,955 in 2008 to $4,876,627 in 2009. This increase was attributable to an increase in oil price and gas production partially offset by a decrease in gas prices and oil production. The average oil price increased 7% from $77.05 per bbl in 2008 to $82.22 per bbl in 2009 and the average gas price decreased 4% from $6.70 in 2008 to $6.41 per mcf in 2009.

Production and exploration. Production costs decreased 4% from $1,240,305 in 2008 to $1,195,584 in 2009, primarily as a result of a 67% decrease in repairs and maintenance to operated wells in the El Cinco field offset by increased production and ad valorem taxes due to the increase in oil and gas sales and gas production. Oil production decreased 3% from 17,504 bbls in 2008 to 17,065 bbls in 2009 and gas production increased 43% from 379,048 mcf in 2008 to 542,099 mcf in 2009.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") expense increased 34% from $779,618 in 2008 to $1,046,120 in 2009 due to an increase in production and an increase in full cost pool partially offset by an increase in gas reserves.

General and administrative expenses. General and administrative expenses increased 7% from $821,786 in 2008 to $876,756 in 2009, primarily as a result of an increase in salaries.

Interest expense. Interest expense decreased 22% from $105,312 in 2008 to $81,961 in 2009 due to a decrease in average borrowings and interest rates during the current fiscal year.

Income taxes. Income tax expense increased from $217,594 in 2008 to $528,262 in 2009, an increase of $310,668. This increase was attributable to our increased income.

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 17%.

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

Production and exploration. Production costs increased 42% from $870,778 in 2007 to $1,240,305 in 2008, primarily as 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 5% from 16,738 bbls in 2007 to 17,504 bbls in 2008 and gas production increased 12% from 339,174 mcf in 2007 to 379,048 mcf in 2008.

Depreciation, depletion and amortization. DD&A expense increased 19% from $652,826 in 2007 to $779,618 in 2008 due to 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 1% from $829,180 in 2007 to $821,786 in 2008, primarily as a result of a decrease in stock option compensation expense partially offset by an increase in engineering and geological services for evaluation of projects.

Interest expense. Interest expense increased 338% from $24,046 in 2007 to $105,312 in 2008 due 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 a small revision of prior year estimates.

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, 2009:

		Payments Due In: (1)		
	Total	less than 1 year	1-3 years	3 years
Contractual obligations:				
Secured bank line of credit	$ 1,400,000	$ -	$ 1,400,000	$ -

(1)Does not include estimated interest of $40,300 less than 1 year and $120,800 1-3 years.

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. 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 ("ARO") 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 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 projects.

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.

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.

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.

Asset Retirement Obligations. 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 April 2008, the FASB issued FASB Staff Position (“FSP”) No. SFAS No. 142-3, Determination of the Useful Life of Intangible Assets (“FSP SFAS No. 142-3”). FSP SFAS No. 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, Goodwill and Other Intangible Assets (“SFAS No. 142”). The intent of FSP SFAS No. 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141R and other applicable accounting literature. FSP SFAS No. 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and must be applied prospectively to intangible assets acquired after the effective date. We are currently evaluating the potential impact, if any, of FSP SFAS No. 142-3 on our financial statements.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, which has been established by the FASB as a framework for entities to identify the sources of accounting principles and for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with US GAAP. SFAS No. 162 is effective 60 days following the SEC’s approval of the Public Company Accounting Oversight Board’s (“PCAOB”) amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. The effective date of SFAS No. 162 was November 15, 2008. The adoption of this Standard did not have a material impact on our financial statements.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (a) report the independence and qualifications of its reserves preparer or auditor; (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (c) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. The Company is currently assessing the impact that adoption of this rule will have on our financial statements, which will vary depending on commodity prices.

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, 2009, 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. On March 31, 2009 we had an outstanding loan balance of $1,400,000 under our $5.0 million revolving credit agreement, which bears interest at an annual rate equal to the British Bankers Association London Interbank Offered Rate ("BBA LIBOR") daily floating rate, plus 2.5 percentage points. If the interest rate on our bank debt increases or decreases by one percentage point our annual pretax income would change by $14,000 based on borrowings at March 31, 2009.

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, 2009, our largest credit risk associated with any single purchaser was $37,513. We are also exposed to credit risk in the event of nonperformance from any of our working interest partners. At March 31, 2009, our largest credit risk associated with any working interest partner was $63,660. 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. 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. Declines in oil and natural gas prices will materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. 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. 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 report on Form 10-K. Similarly, any improvements in oil and gas prices can have a favorable impact on our financial condition, results of operations and capital resources. 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. If the average oil price had increased or decreased by one dollar per barrel for fiscal 2009, our pretax income would have changed by $17,065. If the average gas price had increased or decreased by one dollar per mcf for fiscal 2009, our pretax income would have changed by $542,099.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears on pages F1 through F18 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 evaluate 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, 2009.

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, 2009. Based on such evaluation, such officers have concluded that, as of March 31, 2009, 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 Exchange Act is incorporated by reference to the Proxy Statement for our Annual Meeting of Stockholders, which will be filed with the SEC not later than 120 days after March 31, 2009, the end of the fiscal year covered by this report.

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 not later than 120 days after March 31, 2009, the end of the fiscal year covered by this report.

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 not later than 120 days after March 31, 2009, the end of the fiscal year covered by this report.

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 not later than 120 days after March 31, 2009, the end of the fiscal year covered by this report.

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 not later than 120 days after March 31, 2009, the end of the fiscal year covered by this report.

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
Dated: June 23, 2009		Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below as of June 23, 2009, 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/ Nicholas C. Taylor
Nicholas C. Taylor
Chief Executive Officer, President and Director

/s/ Donna Gail Yanko
Donna Gail Yanko
Vice President and Secretary

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.

BBA LIBOR. British Bankers Association London Interbank Offered Rate. BBA Libor is the most widely used rate for short term interest rates worldwide.

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 at standard atmospheric conditions.

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.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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.

MMBtu. One million British thermal units of energy commonly used to measure heat value or energy content of natural gas.

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 ("NGLs"). 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.

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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, 2009 and 2008 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, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
June 24, 2009

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

	2009	2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 223,583	$ 303,617
Accounts receivable:		
Oil and gas sales	351,040	758,459
Trade	164,834	102,403
Related parties	1,687	12,659
Prepaid costs and expenses	36,610	22,062
Total current assets	777,754	1,199,200
Investment in GazTex, LLC	-	20,509
Property and equipment, at cost		
Oil and gas properties, using the full cost method	26,735,778	23,941,483
Other	61,362	61,362
	26,797,140	24,002,845
Less accumulated depreciation, depletion, and amortization	13,066,014	12,019,895
Property and equipment, net	13,731,126	11,982,950
	$ 14,508,880	$ 13,202,659
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 555,765	$ 571,526
Long-term debt	1,400,000	2,600,000
Asset retirement obligation	440,011	374,789
Deferred income tax liabilities	1,185,494	1,196,280
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;		
1,962,616 and 1,841,366 shares issued;		
1,878,616 and 1,757,366 shares outstanding as of		
March 31, 2009 and 2008, respectively	981,308	920,683
Additional paid-in capital	5,617,620	4,381,269
Retained earnings	4,755,299	3,584,729
Treasury stock, at cost (84,000 shares)	(426,617)	(426,617)
Total stockholders' equity	10,927,610	8,460,064
	$ 14,508,880	$ 13,202,659

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

Mexco Energy Corporation and Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended March 31,

	2009	2008	2007
Operating revenues:			
Oil and gas	$ 4,876,627	$ 3,887,955	$ 2,969,325
Other	49,366	11,453	2,392
Total operating revenues	4,925,993	3,899,408	2,971,717
Operating expenses:			
Production	1,195,584	1,240,305	870,778
Accretion of asset retirement obligation	28,578	26,262	24,057
Depreciation, depletion, and amortization	1,046,120	779,618	652,826
General and administrative	876,756	821,786	829,180
Total operating expenses	3,147,038	2,867,971	2,376,841
Operating profit	1,778,955	1,031,437	594,876
Other income (expense):			
Interest income	1,838	5,113	4,670
Interest expense	(81,961)	(105,312)	(24,046)
Net other expense	(80,123)	(100,199)	(19,376)
Earnings before income taxes and minority interest	1,698,832	931,238	575,500
Income tax expense (benefit):			
Current	539,048	-	-
Deferred	(10,786)	217,594	(28,050)
	528,262	217,594	(28,050)
Earnings before minority interest	1,170,570	713,644	603,550
Minority interest in loss of subsidiary	-	-	4,835
Net income	$ 1,170,570	$ 713,644	$ 608,385
Earnings per common share:			
Basic:	$ 0.63	$ 0.40	$ 0.35
Diluted:	$ 0.61	$ 0.40	$ 0.33
Weighted average common shares outstanding:			
Basic:	1,846,394	1,767,777	1,761,344
Diluted:	1,934,235	1,773,049	1,819,969

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

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, 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
Net income	-	-	-	1,170,570	1,170,570
Issuance of stock through options exercised	60,625	-	642,615	-	703,240
Excess tax benefits from stock-based compensation	-	-	539,048	-	539,048
Stock based compensation	-	-	54,688	-	54,688
Balance, March 31, 2009	$ 981,308	$ (426,617)	$ 5,617,620	$ 4,755,299	$ 10,927,610

	Share Activity		
	2009	2008	2007
Common stock issued			
At beginning of year	1,841,366	1,840,366	1,776,566
Issued	121,250	1,000	63,800
At end of year	1,962,616	1,841,366	1,840,366
Held in treasury			
At beginning of year	(84,000)	(59,525)	(33,525)
Acquisitions	-	(24,475)	(30,000)
Exchange for property	-	-	4,000
At end of year	(84,000)	(84,000)	(59,525)
Common shares outstanding at end of year	1,878,616	1,757,366	1,780,841

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,

	2009	2008	2007
Cash flows from operating activities:			
Net income	$ 1,170,570	$ 713,644	$ 608,385
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax (benefit) expense	(10,786)	217,594	(28,050)
Excess tax benefit from share based payment arrangement	(539,048)	(1,100)	(14,191)
Stock-based compensation	54,688	85,877	126,454
Common stock issued to director	-	-	14,100
Depreciation, depletion, and amortization	1,046,120	779,618	652,826
Accretion of asset retirement obligations	28,578	26,262	24,057
Other	(4,135)	-	-
Minority interest in loss of GazTex, LLC	-	-	(4,835)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	355,960	(411,139)	26,896
(Increase) decrease in prepaid expenses	(14,548)	43,924	(50,146)
Increase in income taxes payable	539,048	-	-
Increase (decrease) in accounts payable and accrued expenses	167,932	20,084	(30,472)
Net cash provided by operating activities	2,794,379	1,474,764	1,325,024
Cash flows from investing activities:			
Additions to oil and gas properties	(2,937,939)	(3,060,194)	(1,545,023)
Proceeds from investment in GazTex, LLC	18,700	-	-
Proceeds from sale of oil and gas properties and equipment	2,538	40,453	28,016
Additions to other property and equipment	-	(9,950)	(11,564)
Net cash used in investing activities	(2,916,701)	(3,029,691)	(1,528,571)
Cash flows from financing activities:			
Acquisition of treasury stock	-	(119,093)	(90,809)
Proceeds from exercise of stock options	703,240	4,000	197,150
Reduction of long-term debt	(2,849,521)	(525,000)	(740,000)
Proceeds from long term debt	1,649,521	2,425,000	840,000
Minority interest contributions	-	-	4,835
Repurchase of OBTX, LLC stock	-	-	(2,051)
Excess tax benefit from share based payment arrangement	539,048	1,100	14,191
Net cash provided by financing activities	42,288	1,786,007	223,316
Net (decrease) increase in cash and cash equivalents	(80,034)	231,080	19,769
Cash and cash equivalents at beginning of year	303,617	72,537	52,768
Cash and cash equivalents at end of year	$ 223,583	$ 303,617	$ 72,537
Supplemental disclosure of cash flow information:			
Cash paid for interest	$ 89,490	$ 97,163	$ 22,736
Income taxes paid	$ -	$ -	$ -

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	$	31,863	$	46,250	$	-
Asset retirement obligations	$	38,247	$	36,729	$	46,355

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. OBTX, LLC was dissolved in March 2009. 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.

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. Declines in oil and natural gas prices will materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Similarly, any improvements in oil and gas prices can have a favorable impact on our financial condition, results of operations and capital resources.

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 and the future development, dismantlement and abandonment costs.

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 ARO 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 DD&A pool). Impairments transferred to the DD&A pool increase the DD&A rate.

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 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.

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.

Asset Retirement Obligations. 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. For the year ended March 31, 2009, the amount of unrecognized tax benefits was approximately $467,164. For the years ended March 31, 2008 and 2009, we did not have any uncertain tax positions.

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.

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 assumes the exercise of all stock options having exercise prices less than the average market price of the common stock during the period using the treasury stock method and 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:

	2009	2008	2007
Weighted average common shares outstanding - basic	1,846,394	1,767,777	1,761,344
Effect of the assumed exercise of dilutive stock options	87,841	5,272	58,625
Weighted average common shares outstanding - dilutive	1,934,235	1,773,049	1,819,969
Earnings per common share:			
Basic:	$ 0.63	$ 0.40	$ 0.35
Diluted:	$ 0.61	$ 0.40	$ 0.33

For the year ended March 31, 2009, no potential common shares relating to stock options were excluded in the computation of diluted net income per share. For the years ended March 31, 2008 and 2007, potential common shares of 240,000 and 135,000, respectively, 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. Anti-dilutive stock options at March 31, 2008 had a weighted average exercise price of $6.49.

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 Mexco has taken less than its ownership share of gas production (under produced). We have no significant gas imbalances.

Stock-based Compensation. We account for stock-based compensation in accordance with SFAS 123(R), "Share-Based Payment," for transactions in which we exchange our equity instruments for employee services. The cost of employee services received in exchange for equity instruments, employee stock options, is measured based on the grant-date fair value of those instruments using the Binomial option pricing model and is recognized as compensation expense 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.

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 April 2008, the FASB issued FASB Staff Position ("FSP") No. SFAS No. 142-3, Determination of the Useful Life of Intangible Assets ("FSP SFAS No. 142-3"). FSP SFAS No. 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, Goodwill and Other Intangible Assets ("SFAS No. 142"). The intent of FSP SFAS No. 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141R and other applicable accounting literature. FSP SFAS No. 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and must be applied prospectively to intangible assets acquired after the effective date. We are currently evaluating the potential impact, if any, of FSP

SFAS No. 142-3 on our financial statements.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, which has been established by the FASB as a framework for entities to identify the sources of accounting principles and for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with US GAAP. SFAS No. 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board's ("PCAOB") amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. The effective date of SFAS No. 162 was November 15, 2008. The adoption of this Standard did not have a material impact on our financial statements.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (a) report the independence and qualifications of its reserves preparer or auditor; (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (c) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. We are currently assessing the impact that adoption of this rule will have on our financial statements, which will vary depending on commodity prices.

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 with no monthly commitment reductions. The borrowing base is evaluated annually, on or about September 1. Amounts borrowed under this agreement are collateralized by the common stock of one of the Company's wholly owned subsidiary and substantially all of our oil and gas properties. In September 2008, the borrowing base was redetermined and set at $4,900,000. Availability of this line of credit at March 31, 2009 was $3,500,000. No principal payments are anticipated to be required through March 31, 2010 based on the revised borrowing base.

In December 2008, the credit agreement was renewed with a maturity date of October 31, 2010. Under the renewed agreement, interest on the facility accrues at an annual rate equal to the BBA LIBOR daily floating rate, plus 2.5 percentage points, which was 3.0225% on March 31, 2009. Interest on the outstanding amount under the credit agreement is payable monthly. In addition we will pay an unused commitment fee in an amount equal to 1/2 of 1 percent (.5%) times the daily average of the unadvanced amount of the commitment. The unused commitment fee shall be payable quarterly in arrears on the last day of each calendar quarter beginning March 31, 2009. The loan agreement contains customary covenants for credit facilities of this type including limitations on disposition of assets, mergers and reorganizations. We are also obligated to meet certain financial covenants under the loan agreement. Mexco is in compliance with all covenants as of March 31, 2009. In addition, this agreement prohibits us from paying cash dividends on our common stock.

At the end of fiscal 2009, two letters of credit for $50,000 each, in lieu of a plugging bond covering the properties we operate were outstanding under the facility, one with the Texas Railroad Commission and one with the State of New Mexico. These letters of credit renew annually. Since we no longer have any well operations and do not plan to have any operations in the State of New Mexico, the letter of credit for the State of New Mexico was not renewed and subsequently cancelled on April 29, 2009.

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 ARO 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, 2009 and 2008:

	2009	2008
Carrying amount of asset retirement obligations as of April 1	$ 424,789	$ 400,584
Liabilities incurred	38,247	36,729
Liabilities settled	(1,603)	(38,786)
Accretion expense	28,578	26,262
Carrying amount of asset retirement obligations as of March 31	490,011	424,789
Less: Current portion	50,000	50,000
Non-Current asset retirement obligation	$ 440,011	$ 374,789

The ARO 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:

	2009	2008	2007
Deferred tax assets:			
Percentage depletion carryforwards	$ 839,900	$ 760,299	$ 667,423
Deferred stock-based compensation	31,468	42,226	39,876
Asset retirement obligation	151,903	131,685	124,182
Net operating loss	29,387	36,445	60,655
Other	4,692	3,168	3,871
	1,057,350	973,823	896,007
Deferred tax liabilities:			
Excess financial accounting bases over tax bases of property and equipment	(2,242,844)	(2,170,103)	(1,874,693)
Net deferred tax liabilities	$ (1,185,494)	$ (1,196,280)	$ (978,686)

As of March 31, 2009, we have statutory depletion carryforwards of approximately $2,709,000, which do not expire. At March 31, 2009, we had a net operating loss carryforward for regular income tax reporting purposes of approximately $1,830,000, 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.

The amount of income taxes recorded by the Company requires the interpretation of complex rules and regulations of federal and state taxing jurisdictions. We are subject to examination by any of these jurisdictions for the fiscal tax years of 2006, 2007 and 2008.

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

	2009	2008	2007

Tax expense at statutory rate	$ 577,603	$ 316,621	$ 197,314
Depletion in excess of basis	(34,100)	(93,000)	(99,200)
Effect of graduated rates	(3,885)	(27,937)	(17,410)
Revision of prior year estimates	(16,833)	7,487	(123,443)
Permanent differences	10,598	14,423	14,689
Other	(5,121)	-	-
	$ 528,262	$ 217,594	$ (28,050)
Effective tax rate	31%	23%	(5%)

6. Investment in GazTex, LLC

Our long-term asset consisted 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 Mexco owns 100% of the interest. 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 profit 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 2009 and 2008, two customers accounted for 32% and 27% of our total revenues, respectively. At March 31, 2009, accounts receivable from these two customers combined were approximately 16% of oil and gas accounts receivable. In fiscal 2007, one customer accounted for 12% of the total revenues.

8. Oil and Gas Costs

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

	2009	2008	2007
Property acquisition costs:			
Proved	$ 1,682,374	$ 1,952,171	$ 603,271
Unproved	-	-	-
Exploration	615,073	820,436	24,493
Development	456,799	685,043	953,271
Capitalized asset retirement obligations	38,247	36,729	46,355
Total costs incurred for oil and gas properties	$ 2,792,493	$ 3,494,379	$ 1,627,390

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

	2009	2008	2007
Proved oil and gas properties	$ 26,565,291	$ 23,770,996	$ 20,355,944
Unproved oil and gas properties:			
subject to amortization	170,487	170,487	170,487
not subject to amortization	-	-	-
	26,735,778	23,941,483	20,526,431
Less accumulated depreciation,			
depletion, and amortization	13,013,448	11,974,477	11,202,369
	$ 13,722,330	$ 11,967,006	$ 9,324,062

Depreciation, depletion, and amortization amounted to $1.62, $1.60 and $1.47 per equivalent mcf of production for the years ended March 31, 2009, 2008, and 2007, 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 50,000 shares at an aggregate cost of $310,609, and during fiscal 2008, we repurchased 24,475 shares at an aggregate cost of $119,093. No shares of our common stock were repurchased for the treasury account during fiscal 2009.

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, we 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 this plan is five years from the date of its adoption.

According to our employee stock incentive plans, new shares will be issued upon the exercise of stock options and the Company can repurchase shares exercised under these plans. 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 and 2009.

We recognized compensation expense of $54,688, $85,877 and $126,454 in general and administrative expense in the Consolidated Statements of Operations for fiscal 2009, 2008 and 2007, respectively. The total cost related to non-vested awards not yet recognized at March 31, 2009 totals $37,724, which is expected to be recognized over a weighted average of 2.07 years.

For the year ended March 31, 2009, employees and directors exercised options on a total of 121,250 shares at exercise prices between $4.00 and $8.24 per share. The Company received proceeds of $703,240 from these exercises. The total intrinsic value of the exercised options was $4,209,381. No tax deduction is recorded when options are awarded. Of these exercised options, 45,750 shares resulted in a disqualifying disposition and a tax benefit for the Company of $539,048 for the year ended March 31, 2009. Mexco issued new shares of common stock to settle these option exercises. Stock options covering 1,000 shares were exercised during the year ended March 31, 2008 and resulted in a disqualifying disposition and a tax benefit of $1,100.

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 2009, 2008 and 2007. All such amounts represent the weighted average amounts for each period.

	For the year ended March 31, 2009	2008	2007
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

No stock options were granted during the year ended March 31, 2009. During the year ended March 31, 2008 and 2007, stock options covering 25,000 and 35,000 shares, respectively, were granted. Stock options covering 121,250 shares were exercised during the year ended March 31, 2009. 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.

No forfeiture rate is assumed for stock options granted to directors or employees due to the forfeiture rate history for these types of awards. On April 2, 2008, 20,000 stock options expired because they were not exercised prior to the end of their ten-year term. During the year ended March 31, 2008, 35,250 vested and 3,750 unvested stock options were forfeited due to the termination of a consulting agreement with a consultant and the resignation of an employee. 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.

The following table is a summary of activity of stock options for the year ended March 31, 2008 and 2009:

	Number of Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contract Life in Years	Aggregate Intrinsic Value
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)
Granted	-	-		
Exercised	(121,250)	5.80		
Forfeited or Expired	(20,000)	7.75		
Outstanding at March 31, 2009	148,750	$ 6.04	3.04	$ (813,703)
Vested at March 31, 2009	115,000	$ 6.03	3.01	$ (630,403)
Exercisable at March 31, 2009	115,000	$ 6.03	3.01	$ (630,403)

Outstanding options at March 31, 2009 expire between September 2009 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:

	2009	2008	2007
Weighted average grant-date fair value of stock options granted (per share)	$ -	$ 4.35	$ 5.15

Total fair value of options vested	$ 82,225	$ 124,300	$ 137,925
Total intrinsic value of options exercised	$ 4,209,381	$ 1,100	$ 110,019

Cash received from option exercise under all share-based payment arrangements for the years ended March 31, 2009, 2008 and 2007, was $703,240, $4,000 and $197,150, respectively.

The following table summarizes information about options outstanding at March 31, 2009:

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	41,250	$ 4.18		
5.25 – 6.49	38,000	5.62		
6.50 – 7.74	40,750	6.76		
7.75 – 8.24	28,750	8.24		
$4.00 – 8.24	148,750	$ 6.04	3.04	$ (813,703)

The following table summarizes information about options exercisable at March 31, 2009:

Range of Exercise Prices	Number Exercisable	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value
$4.00 – 5.24	22,500	$ 4.04	
5.25 – 6.49	38,000	5.62	
6.50 – 7.74	40,750	6.76	
7.75 – 8.24	13,750	8.24	
$4.00 – 8.24	115,000	$ 6.03	$ (630,403)

11. Related Party Transactions

Related party transactions with the majority stockholder for the years ended March 31, 2009, 2008, and 2007 relate to shared office expenditures. The total billed to the stockholder for years ended March 31, 2009, 2008 and 2007 was $40,872, $36,368 and $44,194, respectively.

A Family Limited Partnership of Thomas Craddick received from the Company a finder's fee in kind, equal to 2.5% of the mineral interest purchased in the Newark East Field in Johnson County, Texas in October 2008. Thomas Craddick is a member of the board of directors and Company employee. Mr. Craddick invested his personal funds in a working interest (5.0% before payout and 3.75% after payout) in the Company's well in Ward County, Texas. This personal investment was made on the same basis as an unrelated third party investor.

On April 1, 2007, Jeff Smith, a member of the board of directors through September 11, 2008 and a geological consultant, entered into an agreement with the Company to provide geological consulting services for a fee of approximately $10,000 per month plus expenses. This agreement was amended to $5,000 per month plus expenses on March 1, 2009. The Company incurred charges from Mr. Smith for services rendered under this agreement and subsequent amendment and bonuses of approximately $114,000 for the year ended March 31, 2009. As of March 31, 2009, there was an outstanding invoice of $5,000 payable to Mr. Smith which was subsequently paid on April 15, 2009. Also as part of this agreement, Mr. Smith received from the Company a 0.25% overriding interest in each of the two wells in Loving County, Texas, a 1.0% overriding interest in the well in Ward County, Texas and a .5% overriding interest in the well in Reeves County, Texas. Mr. Smith invested his personal funds in a working interest in the Company's wells in Reeves County, Texas (2.5% before payout and 1.875% after payout) and Ward County, Texas (2.0% before payout and 1.5% after payout), on a non-promoted basis. Royalties paid to Mr. Smith from the Reeves County well were approximately $4,300 for the year ended March 31, 2009.

At March 31, 2009, the Company was owed by these related parties approximately $1,700, which is reflected in accounts receivable — related parties.

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, 2009, 2008, and 2007 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:

	2009		2008		2007	
	Bbls	Mcf	Bbls	Mcf	Bbls	Mcf
Proved reserves, beginning of year	217,000	7,857,000	220,000	6,905,000	183,000	6,697,000
Revision of previous estimates	(24,000)	140,000	(11,000)	109,000	6,000	212,000
Purchase of minerals in place	-	886,000	-	584,000	33,000	199,000
Extensions and discoveries	31,000	1,136,000	26,000	638,000	15,000	136,000
Sales of minerals in place	-	-	-	-	-	-
Production	(17,000)	(542,000)	(18,000)	(379,000)	(17,000)	(339,000)
Proved reserves, end of year	207,000	9,477,000	217,000	7,857,000	220,000	6,905,000
Proved Developed Reserves:						
Beginning of year	122,000	5,050,000	111,000	3,968,000	87,000	3,891,000
End of year	112,000	5,989,000	122,000	5,050,000	111,000	3,968,000

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 $42.12, $96.61 and $59.61 per barrel at March 31, 2009, 2008 and 2007, respectively. The year ended weighted average gas price utilized in the computation of future cash inflows was $3.13, $8.70 and $6.85 per mcf at March 31, 2009, 2008 and 2007, 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 2009	2008	2007
Future cash inflows	$ 38,369,000	$ 89,327,000	$ 60,428,000
Future production and development costs	(11,566,000)	(15,891,000)	(13,181,000)
Future income taxes (a)	(5,306,000)	(15,086,000)	(10,769,000)
Future net cash flows	21,497,000	58,350,000	36,478,000
Annual 10% discount for estimated timing of cash flows	(9,989,000)	(25,852,000)	(16,271,000)
Standardized measure of discounted future net cash flows	$ 11,508,000	$ 32,498,000	$ 20,207,000

(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.

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

	March 31 2009	2008	2007
Sales of oil and gas produced, net of production costs	$ (3,681,000)	$ (2,648,000)	$ (2,099,000)
Net changes in price and production costs	(27,213,000)	9,027,000	1,835,000
Changes in previously estimated development costs	1,116,000	295,000	313,000
Revisions of quantity estimates	(324,000)	(121,000)	825,000
Net change due to purchases and sales of minerals in place	1,572,000	2,343,000	1,362,000
Extensions and discoveries, less related costs	1,931,000	5,025,000	561,000
Net change in income taxes	3,124,000	(2,437,000)	(599,000)
Accretion of discount	4,090,000	2,617,000	2,329,000
Changes in timing of estimated cash flows and other	(1,605,000)	(1,810,000)	(2,244,000)
Changes in standardized measure	(20,990,000)	12,291,000	2,283,000
Standardized measure, beginning of year	32,498,000	20,207,000	17,924,000
Standardized measure, end of year	$ 11,508,000	$ 32,498,000	$ 20,207,000

13. Selected Quarterly Financial Data (Unaudited)

	FISCAL 2009			
	4TH QTR	3RD QTR	2ND QTR	1ST QTR
Oil and gas revenue	$ 700,578	$ 908,253	$ 1,595,209	$ 1,672,587
Operating profit (loss)	(52,505)	217,985	796,586	816,889
Net income (loss)	(10,835)	131,501	511,115	538,789
Net income (loss) per share-basic	(.01)	0.07	0.27	0.31
Net income (loss) per share-diluted	(.01)	0.07	0.26	0.29

	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

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INDEX TO EXHIBITS

Exhibit Number	
3.1*	Articles of Incorporation.
3.2***	Amended Bylaws as amended on November 15, 2008.
10.1**	Stock Option Plan.
10.2*	Bank Line of Credit.
10.3****	2004 Incentive Stock Option Plan.
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 as Exhibit 3.1 with the Company's Quarterly Report on Form 10-Q dated November 13, 2008.
**** 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.