MEXCO ENERGY CORP
Form 10-K
June 29, 2011

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

FORM 10-K

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

For the fiscal year ended March 31, 2011

[ ] 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: Common Stock, $0.50 par value

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

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

Indicate by check-mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 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 [√]

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, 2010 (the last business day of the Registrant's most recently completed second quarter) was $4,635,410 based on Mexco Energy Corporation's closing common stock price of $6.35 per share on that date as reported by the American Stock Exchange.

There were 2,029,949 shares of the registrant's common stock outstanding as of June 15, 2011.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement relating to the 2011 Annual Meeting of Shareholders to be held on September 13, 2011, 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, 2011, the end of the fiscal year covered by this report.

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As used in this document, “the Company”, “Mexco”, “we”, “us” and “our” refer to Mexco Energy Corporation and its consolidated subsidiaries.

Abbreviations or definitions of certain 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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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”). These forward-looking statements are generally located in the material set forth under the headings “Risk Factors”, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”, “Business”, “Properties” but may be found in other locations as well, and are typically identified by the words “could”, “should”, “expect”, “project”, “estimate”, “believe”, “anticipate”, “intend”, “budget”, “plan”, “forecast”, “predict” and other si expressions.

Forward-looking statements generally relate to our 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 and are based upon our management’s reasonable estimates of future results or trends. 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 “Risk Factors”. The factors that may affect our expectations regarding our operations include, among others, the following: our success in development, exploitation and exploration activities; our ability to make planned capital expenditures; declines in our production or prices of oil and gas; our ability to raise equity capital or incur additional indebtedness; our restrictive debt covenants; our acquisition and divestiture activities; weather conditions and events; the proximity, capacity, cost and availability of pipelines and other transportation facilities; increases in the cost of drilling, completion and gas gathering or other costs of production and operations; and other factors discussed elsewhere in this document.

We disclaim any intention or obligation to update or revise any forward-looking statements as a result of new information, future events or otherwise.

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.

In September 2010, Mexco Energy Corporation acquired all of the issued and outstanding stock of Southwest Texas Disposal Corporation, a Texas corporation which owns royalties producing primarily natural gas.

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.

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.

Our total estimated proved reserves at March 31, 2011 were approximately 8.757 billion cubic feet ("Bcf") of natural gas and 290,000 barrels ("bbls") of oil and natural gas liquids, and our estimated present value of proved reserves was approximately $22.7 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 2011, we added proved reserves of 136,000 thousand cubic feet equivalent ("Mcfe") through extensions and discoveries, added 815,000 Mcfe through acquisitions and had upward revisions of previous estimates of 262,000 Mcfe.

Nicholas C. Taylor beneficially owns approximately 44% 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 natural gas, crude oil, condensate and natural gas liquids ("NGLs") 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 2012.

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, 2011, natural gas constituted approximately 83% of our total proved reserves and approximately 58% of our revenues for fiscal 2011. Revenues from oil and gas royalty interests accounted for approximately 38% of our revenues for fiscal 2011.

Newark East (Barnett Shale) Gas Field properties, encompassing 5,414 gross acres, 58 net acres, 136 gross producing wells and .96 net wells in Denton, Johnson, Tarrant and Wise Counties, Texas, account for approximately 9% of our discounted future net cash flows from proved reserves as of March 31, 2011. For fiscal 2011, this field, consisting of royalty interests, accounted for 18% of our gross revenues, 24% of our net revenues.

El Cinco Gas Field properties, encompassing 1,166 gross acres, 886 net acres, 7 gross producing wells and 5.35 net wells in Pecos County, Texas, account for approximately 39% of our discounted future net cash flows from proved reserves as of March 31, 2011. 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 25% are attributable to proven undeveloped reserves which will be developed through re-entry of existing wells and new drilling. For fiscal 2011, these properties accounted for 17% of our gross and net revenues.

Gomez Gas Field properties, encompassing 13,687 gross acres, 72 net acres, 27 gross wells and .13 net wells in Pecos County, Texas, account for approximately 3% of our discounted future net cash flows from proved reserves as of March 31, 2011. For fiscal 2011, these properties accounted for 4% of our gross revenues, 5% of our net revenues. All of these properties, except for one, are royalty interests.

The Haynesville area natural gas properties, purchased in August 2010, encompass 5,132 gross acres, 14 net acres, 6 gross producing wells and .02 net wells in DeSoto Parish, Louisiana and accounted for approximately 4% of our discounted future net cash flows from proved reserves as of March 31, 2011. Of these discounted future net cash flows from proved reserves, approximately 3% are attributable to proven undeveloped reserves. For fiscal 2011, these newly drilled properties, consisting of royalty interests, accounted for 3% of our gross revenues, 4% of our net revenues.

We own interests in and operate 17 producing wells, 1 water injection well and 1 salt water disposal well. We own partial interests in an additional 2,764 producing wells located in the states of Texas, New Mexico, Oklahoma, Louisiana, Alabama, Mississippi, 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)
2011	17,040	459,446
2010	18,036	545,991
2009	17,065	542,099
2008	17,504	379,048
2007	16,738	339,174

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 companies that amounted to 10% or more of revenues for the year ended March 31:

	2011	2010	2009
Chesapeake Operating	14%	18%	22%
Conoco Phillips	5%	14%	10%
Holly / Navajo Refining	13%	4%	4%

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.

Our drilling and production operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits and bonds for the drilling of wells and reports concerning operations. Most states and some counties and municipalities in which we operate also regulate the location of wells; the method of drilling and casing wells; the rates of production or "allowables"; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units and govern the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The Federal Energy Regulatory Commission (“FERC”) regulates under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, interstate natural gas transportation rates and service conditions, which affect the marketing of natural gas we produce, as well as the revenues we receive for sales of such production. Since 1978, various laws have been enacted which 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. Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated. Therefore, we cannot guarantee that the less stringent regulatory approach will continue indefinitely into the future, nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated market prices. Nevertheless, Congress could reenact price controls in the future. The price we receive from the sale of these products is affected by the cost of transporting the products to market. The FERC regulates interstate crude oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate crude oil pipeline rates must be cost-based, although many pipeline charges are today based on historical rates adjusted for inflation and other factors, and other charges may result from settlement rates agreed to by all shippers or market-based rates, which are permitted in certain circumstances. Intrastate crude oil pipeline transportation rates are subject to regulation by state regulatory commissions. Insofar as the interstate and intrastate transportation rates that we pay are generally applicable to all comparable shippers, we believe that the regulation of crude oil transportation rates will not affect our operations in a way that materially differs from the effect on the operations of our competitors who are similarly situated. Further, interstate and intrastate common carrier crude oil pipelines must provide service on an equitable basis. Under this standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When crude oil pipelines operate at full capacity, access is governed by prorating provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to crude oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

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 are some of the existing laws, rules and regulations to which our business is subject:

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 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. 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, for the costs of certain health studies, 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 state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operations of oil and gas properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas may require oil and natural gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and natural gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. Oil and natural gas exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases ("GHGs") and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, many nations have agreed to limit emissions of GHGs pursuant to the United Nations Framework Convention on Climate Change and the "Kyoto Protocol." Although the United States is not participating in the Kyoto Protocol, the U.S. Supreme Court has ruled in Massachusetts, et al. v. EPA, that the Environmental Protection Agency ("EPA") that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, on September 22, 2009, the EPA also issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. The EPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has issued two other rules that would regulate GHGs, one of which regulates GHGs from stationary sources, and one which requires sources in the oil and natural gas exploration and production industry and the pipeline industry to report GHG emissions. The EPA's finding, the greenhouse gas reporting rules, and the rules to regulate the emissions of greenhouse gases may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry. Although it is not possible to predict the impact on our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other GHGs 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 produced waters and other oil and gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the applicable 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.

The Safe Drinking Water Act ("SDWA") and analogous state and local laws regulates the wastewaters produced from oil and gas operations that are disposed via underground injection wells. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and gas production. The main goal of the SDWA is the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In most states, no underground injection may take place except as authorized by permit or rule. We currently own interests in various underground injection wells operated by others and failure to abide by their permits could subject those operators to civil and/or criminal enforcement. We believe that they are in compliance in all material respects with the requirements of applicable state underground injection control programs and their permits.

Many of our operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many newer wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act, i.e., the Fracturing Responsibility and Awareness of Chemicals Act of 2009. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at existing and new well sites as well as increased costs to make our wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. If enacted, these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have considered imposing various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

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, 2011. 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 2012.

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, 2011.

Name	Age	Position
Nicholas C. Taylor	73	President and Chief Executive Officer
Tamala L. McComic	42	Executive Vice President, Treasurer, Assistant Secretary and Chief Financial Officer
Donna Gail Yanko	66	Vice President and Secretary

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 and Director of the Company in April 1983 and continues to serve in such capacity on a part time basis, as required. From July 1993 to the present, Mr. Taylor has been involved in the independent practice of law and other business activities. In November 2005 he was appointed by the Speaker of the House to the Texas Ethics Commission and served until February 2010.

Donna Gail Yanko was appointed to the position of Vice President of the Company in 1990. She has also served as Corporate Secretary since 1992 and from 1986 to 1992 was Assistant Secretary. From 1986 to the present, on a part-time basis, she has assisted the President of the Company in his personal business activities. Ms. Yanko also 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 and was elected Executive Vice President and Chief Financial Officer in July 2009. She served the Company as Vice President and Chief Financial Officer from 2003 to 2009. Prior thereto, Ms. McComic was appointed Treasurer and Assistant Secretary of the Company.

Employees

As of March 31, 2011, we had two full-time and three part-time employees. We believe that relations with these employees are generally satisfactory. From time to time, we utilize the services of independent geological, land and engineering consultants on a limited basis and expect to continue to do so in the future.

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 annual, quarterly and current reports, proxy statements and other information with the Security Exchange Commission ("SEC"). Please call the SEC at 1-800-SEC-0330 for information on the public reference room. The SEC maintains an internet website (www.sec.gov) that contains annual, quarterly and current reports, proxy statements and other information that issuers, including Mexco, 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 www.prars.com, free of charge, as soon as practicable after providing such report to the SEC.

We also maintain an internet website at www.mexcoenergy.com. In the Investor Relations section, our website contains our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other reports and amendments to those reports as soon as reasonably practicable after such material is electronically filed with the SEC. Information on our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with 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 AND INDUSTRY

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. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on a twelve month un-weighted first-day-of-the-month average oil and gas prices for the twelve months prior to the date of the report. Actual future prices and costs may be materially higher or lower.

An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flow from operations.

Our oil and gas is priced in the local markets where it is produced based on local or regional supply and demand factors. The prices we receive for our oil and gas are typically lower than the relevant benchmark prices, such as The New York Mercantile Exchange ("NYMEX"). The difference between the benchmark price and the price we receive is called a differential. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Additionally, insufficient pipeline capacity, lack of demand in any given operating area or other factors may cause the differential to increase in a particular area compared with other producing areas. During fiscal 2011, differentials averaged $2.77 per Bbl of oil and $0.23 per Mcf of gas. Increases in the differential between the benchmark prices for oil and gas and the wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

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 44% of our total estimated net proved reserves at March 31, 2011 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 not be able to fund the capital expenditures that will be required for us to increase reserves and production.

We must make capital expenditures to develop our existing reserves and to discover new reserves. Historically, we have used our cash flow from operations and borrowings under our revolving credit facility to fund our capital expenditures and we expect to continue to do so in the future.

Volatility in oil and gas prices, the timing of our drilling programs and drilling results will affect our cash flow from operations. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flow from operations does not increase as a result of planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and operating expenses and our planned capital expenditures would, by necessity, be decreased.

The borrowing base under our credit facility will be determined from time to time by the lender. Reductions in estimates of oil and gas reserves could result in a reduction in the borrowing base, which would reduce the amount of financial resources available under the credit facility to meet our capital requirements. Such a reduction could be the result of lower commodity prices and/or production, inability to drill or unfavorable drilling results, changes in oil and gas reserve engineering, the lenders' inability to agree to an adequate borrowing base or adverse changes in the lenders' practices regarding estimation of reserves.

If cash flow from operations or our borrowing base decrease for any reason, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited. In addition, if the borrowing base under the credit facility is reduced, we would be required to reduce our borrowings under the credit facility so that such borrowings do not exceed the borrowing base. This could further reduce the cash available to us for capital spending and, if we did not have sufficient capital to reduce our borrowing level, we may be in default under the credit facility.

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.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce crude oil or natural gas from these or any other potential drilling locations.

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.

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.

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.

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.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact our revenues.

Legislation has been introduced in the U.S. Congress to amend the federal SDWA to subject hydraulic fracturing operations to regulation under the SDWA and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas and, to a lesser extent, oil production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with wells for which we are the operator. Sponsors of bills currently pending in Congress have asserted that chemicals used in the fracturing process may be adversely impacting drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process are impairing groundwater or causing other damage. These bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal or state level. Any such added regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of natural gas and oil, which could adversely affect our revenues and results of operations. Certain states and other agencies have adopted or are considering similar disclosure legislation, moratoria or enforcement initiatives relating to hydraulic fracturing. These legislative and regulatory initiatives, to the extent they are adopted or continue, could prohibit or limit our ability to develop our crude oil and natural gas properties located in unconventional formations, which would adversely affect our ability to access, develop and book reserves in the future.

In March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on human health and the environment. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector, and has already commenced one potential enforcement matter in Texas. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

The current administration's fiscal year 2012 budget proposal released February 14, 2011 contains and members of the U.S. Congress have considered significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to: (1) the repeal of the percentage depletion allowance for oil and natural gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for certain domestic production activities, and (4) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or Congressional considerations in U.S. federal income tax laws could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

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 44% 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.

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, 2011, our executive officers and directors beneficially owned approximately 50% 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.

As a public company we incur legal, accounting and other expenses under the Sarbanes-Oxley Act of 2002 ("SOX"), 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.

Failure of the Company's internal control over financial reporting could harm its business and financial results.

The management of Mexco is 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 United States. Internal control over financial reporting includes maintaining records that in reasonable detail accurately and fairly reflect Mexco'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 our 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, 2011, we had interests in 2,781 gross (26 net) oil and gas wells and owned leasehold interests in approximately 313,244 gross (3,358 net) acres.

Oil and Natural Gas Reserves

In December 2008, the SEC approved revisions to modernize the oil and gas reserves reporting requirements. The new requirements provide for consideration of new technologies in evaluating reserves, allow companies to disclose their probable and possible reserves to investors, report oil and gas reserves using an average price based on the prior 12-month period rather than year-end prices, and revise the disclosure requirements for oil and gas operations. We adopted the new rules effective March 31, 2010.

In accordance with the new guidelines, the average prices used in computing reserves at March 31, 2011 were $77.27 per bbl of oil and $3.88 per mcf of natural gas, based on the 12-month average market prices for sales of oil and natural gas on the first calendar day of each month during fiscal 2011. The benchmark price of $80.04 per bbl of oil was adjusted by lease for gravity, transportation fees and regional price differentials. The benchmark price of $4.11 per mcf of natural gas was adjusted by lease for BTU content, transportation fees and regional price differentials. The average prices used in computing reserves at March 31, 2010 were $66.21 per bbl of oil and $3.77 per mcf of natural gas, based on the 12-month average market prices for sales of oil and natural gas on the first calendar day of each month during fiscal 2010. The benchmark prices used in computing reserves at March 31, 2010 were $69.64 per bbl of oil and $3.98 per mcf of natural gas. Reserves for fiscal 2009 were based on pricing posted on March 31, 2009 based on the oil and gas disclosure requirements effective during that period. Prices used for fiscal 2009 were $42.12 per bbl of oil and $3.13 per mcf of natural gas.

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.

The engineering report with respect to Mexco’s estimates of proved oil and gas reserves as of March 31, 2011, 2010 and 2009 is based on evaluations prepared by Joe C. Neal and Associates, Petroleum and Environmental Engineering Consultants, based in Midland, Texas (“Neal and Associates”) and is filed as Exhibit 99.1 to this annual report.

Management maintains internal controls designed to provide reasonable assurance that the estimates of proved reserves are computed and reported in accordance with rules and regulations provided by the SEC. As stated above, Mexco retained Neal and Associates to prepare estimates of our oil and gas reserves. Management works closely with this firm, and is responsible for providing accurate operating and technical data to it. Our Chief Financial Officer who has over 18 years experience in the oil and gas industry reviews the final reserves estimate and consults with a degreed geological consultant with extensive geological experience and if necessary, discusses the process used and findings with Mr. Neal. Mr. Neal is responsible for overseeing the preparation of the reserve estimates and holds a bachelor’s degree in mechanical engineering (petroleum option), is a member of the Society of Petroleum Engineers and has over 50 years of experience in the oil and gas industry. Our President and Chief Executive Officer who has close to 30 years experience in the oil and gas industry also reviews the final reserves estimate.

Numerous uncertainties exist in estimating quantities of proved reserves. Reserve estimates are imprecise and subjective and may change at any time as additional information becomes available. Furthermore, estimates of oil and gas reserves are projections based on engineering data. There are uncertainties inherent in the interpretation of this data as well as the projection of future rates of production. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

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.

The prices used to calculate 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 during the year ended March 31, 2011, and no major discovery is believed to have caused a significant change in our estimates of proved reserves since that date.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

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, 2011	2010	2009
Oil (Bbls):			
Proved developed – Producing	156,346	138,431	78,959
Proved developed – Non-producing	3,629	3,549	32,732
Proved undeveloped	130,187	98,088	95,694
Total	290,162	240,068	207,385
Natural gas (Mcf):			
Proved developed – Producing	3,895,656	3,952,172	4,326,857
Proved developed – Non-producing	1,068,405	1,065,170	1,662,641
Proved undeveloped	3,792,974	3,388,248	3,487,579
Total	8,757,035	8,405,590	9,477,077
Total net proved reserves (Mcfe)	10,498,007	9,845,998	10,721,387
PV-10 Value (1)	$22,653,390	$18,085,370	$14,348,450
Present value of future income tax discounted at 10%	(5,001,390)	(3,925,370)	(2,840,450)
Standardized measure of discounted future net cash flows (2)	$17,652,000	$14,160,000	$11,508,000
Prices used in Calculating Reserves: (3)			
Natural gas (per Mcf)	$3.88	$3.77	$3.13
Oil (per Bbl)	$77.27	$66.21	$42.12

(1) The PV-10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10% per annum, which is the most directly comparable GAAP financial measure. 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. 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. Our reconciliation of this non-GAAP financial measure is shown in the table as the PV-10, less future income taxes, discounted at 10% per annum, resulting in the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%.

(2)

In accordance with SEC requirement, the standardized measure of discounted future net cash flows for 2011 and 2010 was computed by applying 12-month average prices for oil and gas during fiscal 2011 to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The standardized measure of discounted future net cash flows for 2009 was computed by applying year-end prices of oil and gas. The estimated future net cash flows are then discounted using a rate of 10%.

(3) These prices reflect adjustment by lease for quality, transportation fees and regional price differentials.

During the fiscal year ending March 31, 2011, 11 wells in the DCCO Unit in Denton County, Texas were developed converting gas reserves of approximately 17,000 mcf from proved undeveloped to proved developed. We also participated in the development of 32 wells converting reserves of approximately 37,000 mcfe from proved undeveloped to proved developed. The capital cost was approximately $11,000 for 5 of these wells in which we own a working interest.

Oil and gas prices significantly impact the calculation of the PV-10 and the standardized measure of discounted future net cash flows. The present value of future net cash flows does not purport to be an estimate of the fair market value of the Company's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standards Board (“FASB”) pronouncements, may not necessarily be the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

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, 2011:

	Gross	Net
Oil	1,649	15
Gas	1,132	11
Total Productive Wells	2,781	26

The following table sets forth the approximate developed acreage in which we held a leasehold mineral or other interest as of March 31, 2011:

	Developed Acres	
	Gross	Net
Texas	160,581	2,894
Oklahoma	48,506	207
New Mexico	20,717	146
Louisiana	36,475	52
North Dakota	24,919	21
Kansas	8,520	24
Montana	7,868	5
Wyoming	3,578	5
Mississippi	1,280	2
Alabama	640	2
Colorado	1,120	1
Arkansas	320	-
Total	314,524	3,359

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, 2011, we own approximately 1,477 gross and 737 net acres of material undeveloped acreage located in the Pembrook Unit of Upton County, Texas which is operated by Pioneer Natural Resources USA, Inc. and held by production from approximately 200 wells.

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,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	-	-	-	-	2	.28
Nonproductive	-	-	-	-	-	-
Total	-	-	-	-	2	.28
Development Wells						
Productive	8	.17	21	.25	12	.55
Nonproductive	-	-	2	.01	-	-
Total	8	.17	23	.26	12	.55

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 ("bbl") 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,		
	2011	2010	2009
Oil (a):			
Production (Bbls)	17,040	18,036	17,065
Revenue	$1,332,395	$1,194,500	$1,403,076
Average Bbls per day	47	49	47
Average sales price per Bbl	$78.19	$66.23	$82.22
Gas (b):			
Production (Mcf)	459,446	545,991	542,099
Revenue	$1,812,852	$2,026,263	$3,473,551
Average Mcf per day	1,259	1,496	1,485
Average sales price per Mcf	$3.95	$3.71	$6.41
Production cost:			
Production cost	$772,500	$762,913	$783,855
Production and ad valorem taxes	$253,432	$291,311	$411,729
Equivalent Mcf (c)	561,686	654,207	644,489
Production cost per equivalent Mcf	$1.38	$1.17	$1.22
Production cost per sales dollar	$0.25	$0.24	$0.16
Total oil and gas revenue	$3,145,247	$3,220,763	$4,876,627

(a) Includes condensate.

(b) Includes natural gas products.

(c) Oil production is converted to equivalent mcf at the rate of 6 mcf per 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. REMOVED AND RESERVED

None.

PART II

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

Market Information

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). The following table sets forth certain information as to the high and low sales price quoted for Mexco's common stock on the American Stock Exchange.

	High	Low
2011:		
April - June 2010	$ 10.16	$ 7.55
July - September 2010	7.55	5.60
October - December 2010	8.18	5.90
January - March 2011	15.75	6.99
2010:		
April - June 2009	$ 17.17	$ 9.64
July - September 2009	14.00	10.00
October - December 2009	13.50	8.57
January - March 2010	10.63	7.20

On June 14, 2011, the closing price was $8.80.

Stockholders

As of March 31, 2011, we had approximately 2,089,116 shares issued and 1,152 shareholders of record which does not include shareholders for whom shares are held in a "nominee" or "street" name.

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.

Securities Authorized for Issuance Under Compensation Plans

The following table includes certain information about our Employee Incentive Stock Plans as of March 31, 2011, each of which has been approved by our stockholders.

	Number of Shares Authorized for Issuance under Plan	Number of Shares to be Issued upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Shares Remaining Available for Future Issuance under Plan
1997 Plan	350,000	10,000	$ 4.00	-
2004 Plan	375,000	3,750	$ 4.35	-
2009 Plan	200,000	40,000	$ 6.23	160,000
Total	925,000	53,750	$ 5.69	160,000

Issuer Repurchases

In June 2010, the board of directors authorized the use of up to $250,000 to repurchase shares of our common stock for the treasury account. During fiscal 2011, we repurchased 2,000 shares at an aggregate cost of $12,325. There were no shares of our common stock repurchased for the treasury account during fiscal 2010 and 2009.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

Not applicable.

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. The Company does not have any delivery commitments to provide a fixed and determinable quantity of its oil and gas under any existing contract or agreement.

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

In fiscal 2011, we primarily used cash provided by operations ($1,335,460) and net proceeds from long-term debt ($1,100,000) to fund oil and gas property acquisitions and development ($2,435,374). We had working capital of $470,253 as of March 31, 2011 compared to working capital of $478,394 as of March 31, 2010, a decrease of $8,141.

During the fiscal year ended March 31, 2011, we repurchased 2,000 shares for the treasury at an aggregate cost of $12,325.

In August 2010, we purchased overriding royalty interests averaging .28% in 5,120 gross acres covering eight sections in the Haynesville trend area of DeSoto Parish, Louisiana, for an approximate purchase price of $1.65 million. The Company paid $1.46 million in cash and the remainder was paid as 26,833 shares of its common stock issued from treasury shares. This acreage currently contains six (6) horizontal wells producing from the Haynesville Shale formation with an additional well currently drilling. Petrohawk Operating Company will operate six of the eight sections. The two remaining sections will be operated by Chesapeake Energy. This acreage contains an additional 57 potential drill sites in the Haynesville. Other wells drilled in the Haynesville area show the presence of at least two (2) other potential producing zones, the Bossier and Cotton Valley, which are held by production and available for development should conditions warrant. Hundreds of Haynesville, hundreds of Cotton Valley and several dozen Bossier Shale wells are currently producing in the Haynesville trend area. Any development of these royalties will be free to the Company of expenses for drilling and operations. The Haynesville area has been estimated to become the largest gas resource in the United States and the fourth largest in the world subject to realization of technical estimates, according to World Oil in its June 2010 edition. World Oil recognizes DeSoto Parish as one of the top six (6) parishes of Louisiana where the most productive Haynesville wells are located.

On September 30, 2010, we purchased all of the outstanding stock of Southwest Texas Disposal Corporation, a Texas corporation which owns royalties producing primarily natural gas and free of drilling, development and operating expenses. The cash purchase price of $478,000 was funded from our $4.9 million credit facility. These royalties cover over 300 wells located in 60 counties and parishes in Oklahoma, Texas, Louisiana, New Mexico, Mississippi and Alabama.

In March 2011, we purchased working interests in 160 gross acres in the Fuhrman-Mascho Field of Andrews County, Texas, for an approximate cash purchase price of $670,000 funded from our $4.9 million credit facility. This acreage contains five (5) wells, three of which are producing from the San Andres, one recently drilled well producing from the Grayburg and San Andres formations at an approximate depth of 5,000 feet and one well currently shut-in. These wells are operated by Cone and Petree Oil & Gas Exploration, Inc. The Company owns working interests of approximately 10.8% (7.77% net revenue interest) in this property. This property contains an additional 11 potential drill sites in the Grayburg and San Andres formations with more dense spacing of approximately 10 acres per well. This new spacing in the Fuhrman-Mascho Field has been shown to increase production. The Fuhrman-Mascho Field of Andrews County, Texas was discovered in 1930. This field currently contains approximately 2400 producing wells. Cumulative production from the field to date is approximately 122 million barrels of oil and 122 billion cubic feet of gas.

During fiscal 2011, we participated in 5 wells in the Dodd Federal Unit operated by Concho Resources, Inc. (formerly Marbob Energy Corporation). This unit, located in Eddy County, New Mexico currently contains approximately 110 wells and is expected to contain approximately 170 wells when completely drilled. For the fiscal year ending March 31, 2010, we participated in the drilling of 7 producing wells in this unit. Our working interest in this unit is .185% (.14% net revenue interest).

During the fourth quarter of fiscal 2011, a joint venture in which we are a working interest partner drilled a development well in the Cement Field in Grady County, Oklahoma to test the Yule sand member of the Hoxbar formation. This joint venture originally consisted of wells producing from the Cunningham sand. Our share of the costs to drill and complete this well through March 2011 for our 5% working interest was approximately $64,000.

We currently hold royalty interests in approximately 143 mineral acres in Johnson County, Texas. As of March 31, 2010, there were 3 development wells in the Newark East (Barnett Shale) Field on this acreage producing natural gas into a sales pipeline. In January 2011, 1 additional well was completed and began producing natural gas.

We currently hold royalty interests in an aggregate of 522 acres in the Newark East (Barnett-Shale) Field of Tarrant County, Texas. In August 2010, an additional well was completed and put on production. As of March 31, 2011, this acreage now has 10 producing horizontal natural gas wells and 4 proven undeveloped well locations as well as additional potential drill sites.

At March 31, 2011, we reported estimated PUDs of 4.6 bcfe, which accounted for 44% of our total estimated proved oil and gas reserves. This figure primarily consists of a projected 23 new wells, 6 of which we operate, and 1 new zone behind pipe from a currently producing wellbore that we also operate. We project 1 operated well to be drilled in fiscal 2012, 4 in fiscal 2013 and 1 in fiscal 2014. Regarding the remaining 17 PUD locations operated by others, a location is currently being prepared to drill 1 well with plans for a second well to follow, 5 wells in 2012, 6 in 2013 and 4 in 2014.

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 and, if appropriate, sales of our common stock. See Note 5 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. 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 makes it extremely difficult to predict future oil and natural gas price movements with any certainty. For example in the last twelve months, the West Texas Intermediate ("WTI") posted price for crude oil has ranged from a low of $64.50 per bbl in May 2010 to a high of $103.25 per bbl in March 2011. The Henry Hub Spot Market Price ("Henry Hub") for natural gas has ranged from a low of $3.18 per MMBtu in October 2010 to a high of $5.17 per MMBtu in June 2010. On March 31, 2011 the WTI posted price for crude oil was $103.25 per bbl and the Henry Hub spot price for natural gas was $4.31 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 2011 Compared to Fiscal 2010

Net income was $155,696 for the year ended March 31, 2011, as compared to net income of $400,839 for the year ended March 31, 2010.

Oil and gas sales. Revenue from oil and gas sales was $3,145,247 for the year ended March 31, 2011, a 2% decrease from $3,220,763 for the year ended March 31, 2010. This resulted from a decrease in oil and gas production and partially offset by an increase in oil and gas prices. The following table sets forth our oil and gas revenues, production quantities and average prices received the fiscal year ended March 31.

		2011		2010	% Difference	
Oil:						
Revenue	$	1,332,395	$	1,194,500	11.5	%
Volume (bbls)		17,040		18,036	(5.5	%)
Average Price (per bbl)	$	78.19	$	66.23	18.1	%
Gas:						
Revenue	$	1,812,852	$	2,026,263	(10.5	%)
Volume (mcf)		459,446		545,991	(15.9	%)
Average Price (per mcf)	$	3.95	$	3.71	6.5	%

Production and exploration. Production costs were $1,025,932 in fiscal 2011, a 3% decrease from $1,054,224 in fiscal 2010. This was primarily the result of a decrease in production taxes due to the decrease in oil and gas sales.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") expense was $1,047,906 in fiscal 2011, a 6% decrease from $1,113,141 in fiscal 2010, primarily due to a decrease in production and an increase in reserves partially offset by an increase to the full cost pool amortization base.

General and administrative expenses. General and administrative expenses were $877,790 for the year ended March 31, 2011, a 1% increase from $870,558 for the year ended March 31, 2010. This was primarily due to an increase in stock option compensation expense offset by a decrease in legal fees from the previous year for preparation of the Form S-8.

Interest expense. Interest expense was $36,361 in fiscal 2011, a 10% increase from $33,082 in fiscal 2010, due to an increase in borrowings.

Income taxes. There was an income tax benefit of $15,596 in fiscal 2011 compared to an income tax benefit of $257,235 in fiscal 2010. The 2010 benefit was primarily a result of a change in estimate related to the statutory depletion carryforward upon completion of the 2008 tax return.

Fiscal 2010 Compared to Fiscal 2009

Net income was $400,839 for the year ended March 31, 2010, a 66% decrease from $1,170,570 for the year ended March 31, 2009.

Oil and gas sales. Revenue from oil and gas sales was $3,220,763 for the year ended March 31, 2010, a 34% decrease from $4,876,627 for the year ended March 31, 2009. This resulted from a decrease in oil and gas prices partially offset by an increase in oil and gas production. The following table sets forth our oil and gas revenues, production quantities and average prices received the fiscal year ended March 31.

		2010		2009	% Difference	
Oil:						
Revenue	$	1,194,500	$	1,403,076	(14.9	%)
Volume (bbls)		18,036		17,065	5.7	%
Average Price (per bbl)	$	66.23	$	82.22	19.4	%
Gas:						
Revenue	$	2,026,263	$	3,473,551	(41.7	%)
Volume (mcf)		545,991		542,099	0.7	%
Average Price (per mcf)	$	3.71	$	6.41	(42.1	%)

Production and exploration. Production costs were $1,054,224 in fiscal 2010, a 12% decrease from $1,195,584 in fiscal 2009. This was primarily the result of a decrease in production taxes due to the decrease in oil and gas sales.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense was $1,113,141 in fiscal 2010, a 6% increase from $1,046,120 in fiscal 2009, primarily due to an increase to the full cost pool amortization base, an increase in production and a decrease in reserves.

General and administrative expenses. General and administrative expenses were $870,558 for the year ended March 31, 2010, a 1% decrease from $876,756 for the year ended March 31, 2009. This was due to a decrease in consulting services and salaries partially offset by an increase in legal fees in preparation of the Form S-8 to register shares that may be issued under the Company's 2009 Employee Incentive Stock Plan.

Interest expense. Interest expense was $33,082 in fiscal 2010, a 60% decrease from $81,961 in fiscal 2009 due to a decrease in borrowings and interest rate.

Income taxes. There was an income tax benefit of $257,235 in fiscal 2010 compared to an income tax expense of $528,262 in fiscal 2009. The 2010 benefit was primarily a result of a change in estimate related to the statutory depletion carryforward upon completion of the 2008 tax return.

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, 2011:

		Payments due in (1):		
	Total	less than 1 year	1 -3 years	3 years
Contractual obligations:				

Secured bank line of credit	$1,800,000	$-	$1,800,000	$-

(1) Does not include estimated interest of $49,500 less than 1 year and $148,400 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.

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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.

Other Matters

Critical Accounting Policies and Estimates

In preparing financial statements, management makes informed judgments, estimates and assumptions 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 to determine 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 are based on the quantities of oil and gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Our reserve estimates and the projected cash flows are derived from these reserve estimates, in accordance with SEC guidelines by an independent engineering firm based in part on data provided by us. 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. 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 new SEC requirements, the cost ceiling represents the present value (discounted at 10%) of net cash flows from sales of future production using the average price over the prior 12-month period.

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, estimates and assumptions 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. In addition, significant estimates are used in determining year end proved oil and gas reserves. Although management believes its estimates and assumptions are reasonable, actual results may differ materially from those estimates. The estimate of our oil and natural gas reserves, which is used to compute DD&A and impairment of oil and gas properties, is the most significant of the estimates and assumptions that affect these reported results.

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.

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.

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 December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting. The revised rules are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. In January 2010, the Financial Accounting Standards Board ("FASB") issued guidance that aligns the FASB's oil and gas reserve estimation and disclosure requirements with the new SEC rule revisions. The accounting standards revised the definition of proved reserves to permit consideration of new technologies in evaluating oil and natural gas reserves; require the use of an average price based on the prior twelve month period rather than year-end prices; permit the disclosure of probable and possible oil and gas reserves; require the reporting of the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates; and, revise the disclosure requirements for oil and gas operations. The final rules and new guidance are effective for fiscal years ending on or after December 31, 2009. Mexco adopted these requirements as of March 31, 2010 and the results of the adoption are contained herein.

In January 2010, the FASB issued Accounting Standards Update ("ASU") No. 2010-06, Fair Value Measurements and Disclosures (Topic 820). ASU No. 2010-06 amends Accounting Standards Codification ("ASC") Topic 820 with new guidance and clarifications for improving disclosures about fair value measurements. This guidance requires enhanced disclosures regarding transfers of assets and liabilities between Level 1 (quoted prices in active market for identical assets or liabilities) and Level 2 (significant other observable inputs) of the fair value measurement hierarchy, including the reasons and the timing of the transfers. Additionally, the guidance requires a roll forward of activities on purchases, sales, issuance, and settlements of the assets and liabilities measured using significant unobservable inputs (Level 3 fair value measurements). ASU No. 2010-06 became effective for the Company beginning January 1, 2010, except for the disclosure on the roll forward activities for Level 3 fair value measurements, which will become effective for the Company with the reporting period beginning April 1, 2011. Other than requiring additional disclosures, adoption of this new guidance did not have any effect on the financial statements.

In December 2010, the FASB issued ASU No. 2010-29, Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations. ASU No. 2010-29 amends ASC Topic 805 and reflects the decision reached in Emerging Issues Task Force ("EITF") Issue No. 10-G. The amendments in this ASU specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU No. 2010-29 becomes effective prospectively for the Company with the reporting period beginning April 1, 2011. The Company does not anticipate that adoption of this new guidance will have a material impact on its financial statements.

There were various other accounting standards and interpretations issued during our fiscal year, all of which have been determined to be not applicable or significant by management and once adopted are not expected to have a material impact on the Company's financial position, operations or cash flows.

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, 2011, 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, 2011, we had an outstanding loan balance of $1,800,000 under our $4.9 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 $18,000 based on borrowings at March 31, 2011.

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, 2011, our largest credit risk associated with any single purchaser was $53,175. We are also exposed to credit risk in the event of nonperformance from any of our working interest partners. At March 31, 2010, our largest credit risk associated with any working interest partner was $1,604. 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. 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.

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 2011, our oil and gas revenue would have changed by $17,040. If the average gas price had increased or decreased by one dollar per mcf for fiscal 2011, oil and gas revenue would have changed by $459,446.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears on pages F1 through F19 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

Management's Annual Report on Internal Control over Financial Reporting. Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, our principal executive and principal financial officers and implemented by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. 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. 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, 2011.

This annual report does not include an attestation of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to audit by our independent registered public accounting firm pursuant to temporary rules of the SEC that permit us to provide only management's report in this annual report.

Changes in Internal Control over Financial Reporting. No changes in the Company's internal control over financial reporting occurred during the year ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Evaluation of Disclosure Controls and Procedures. 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. At the end of the period covered by this report, our principal executive officer and principal financial officer reviewed and evaluated the effectiveness of our disclosure controls and procedures, as defined in Exchange Act Rules 13a-15(e) and 15d-15(e). Based on such evaluation, such officers concluded that, as of March 31, 2011, our disclosure controls and procedures were effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act is disclosed within the time periods specified in the SEC's rules and forms and are effective to ensure that information required to be disclosed by us is accumulated and communicated to them to allow timely decisions regarding required disclosure.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

See "Mexco Energy Corporation Board of Directors", "Named Executive Officers Who Are Not Directors", "Section 16(a) Beneficial Ownership Reporting Compliance", "Corporate Governance and Code of Business Conduct" and "Meetings and Committees of the Board of Directors" in the Proxy Statement of Mexco Energy Corporation for our Annual Meeting of Stockholders to be held September 13, 2011 ("Proxy Statement") to be filed with the SEC within 120 days after the end of our fiscal year ended March 31, 2011, which is incorporated herein by reference.

The information required by this item with respect to executive officers of the Company is also set forth in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be contained in the Proxy Statement under the caption "Executive Compensation", and is hereby incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item will be contained in the Proxy Statement under the captions “Security Ownership of Certain Beneficial Owners and Management” and “Employee Incentive Stock Option Plans”, and is hereby incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item will be contained in the Proxy Statement under the captions “Certain Relationships and Related Transactions” and “Meetings and Committees of the Board of Directors”, and is hereby incorporated by reference herein.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be contained in the Proxy Statement under the caption “Audit Fees and Services”, and is hereby incorporated by reference herein.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Consolidated Financial Statements. 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.

Financial Statement Schedules. All schedules have been omitted because they are not applicable, not required under the instructions or the information requested is set forth in the consolidated financial statements or related notes thereto.

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 F20 of this report.

SIGNATURES

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

MEXCO ENERGY CORPORATION

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

By: /s/ Tamala L. McComic
Executive Vice President and
Chief Financial Officer

Dated: June 29, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below as of June 29, 2011, by the following persons on behalf of the Registrant and in the capacity indicated.

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

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

/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/ Paul G. Hines
Paul G. Hines
Director

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

Glossary of Abbreviations and Terms

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report.

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 herein in reference to crude oil, condensate or natural gas liquids hydrocarbons.

Bcf. One billion cubic feet of natural gas at standard atmospheric conditions.

BTU. British thermal unit.

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.

Exploitation. The continuing development of a known producing formation in a previously discovered field. To make complete or maximize the ultimate recovery of oil or natural gas from the field by work including development wells, secondary recovery equipment or other suitable processes and technology.

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.

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

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.

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.

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.

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%.

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.

Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-acre spacing) and is often established by regulatory agencies.

Standardized measure of discounted future net cash flows. The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, and a 10% annual discount rate. The information for this calculation is included in the note regarding disclosures about oil and gas reserve data contained in the Notes to Consolidated Financial Statements included in this Form 10-K.

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.

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Wellbore. The hole drilled by the bit that is equipped for crude oil or natural gas production on a completed well. Also called well or borehole.

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.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Mexco Energy Corporation

We have audited the accompanying consolidated balance sheets of Mexco Energy Corporation and Subsidiaries as of March 31, 2011 and 2010 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, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted the new oil and gas reserve estimation and disclosure requirements as of March 31, 2010.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
June 29, 2011

Mexco Energy Corporation and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	March 31, 2011	March 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$179,071	$160,439
Accounts receivable:		
Oil and gas sales	384,215	538,444
Trade	42,432	63,455
Related parties	-	55
Prepaid costs and expenses	64,479	17,161
Total current assets	670,197	779,554
Property and equipment, at cost		
Oil and gas properties, using the full cost method	30,426,817	27,353,016
Other	78,520	76,161
	30,505,337	27,429,177
Less accumulated depreciation, depletion and amortization	15,227,063	14,179,156
Property and equipment, net	15,278,274	13,250,021
	$15,948,471	$14,029,575
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$199,944	$301,160
Long-term debt	1,800,000	700,000
Asset retirement obligations	528,911	486,305
Deferred income tax liabilities	912,663	902,757
Commitments and contingencies		
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; 2,089,116 and 2,003,866 shares issued; 2,029,949 and 1,919,866 shares outstanding as of March 31, 2011 and 2010, respectively	1,044,558	1,001,933
Additional paid-in capital	6,453,226	5,907,899
Retained earnings	5,311,834	5,156,138
Treasury stock, at cost (59,167 and 84,000 shares, respectively)	(302,665)	(426,617)
Total stockholders' equity	12,506,953	11,639,353
	$15,948,471	$14,029,575

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,

	2011	2010	2009
Operating revenues:			
Oil and gas	$3,145,247	$3,220,763	$4,876,627
Other	16,611	24,993	49,366
Total operating revenues	3,161,858	3,245,756	4,925,993
Operating expenses:			
Production	1,025,932	1,054,224	1,195,584
Accretion of asset retirement obligation	34,129	31,625	28,578
Depreciation, depletion and amortization	1,047,906	1,113,141	1,046,120
General and administrative	877,790	870,558	876,756
Total operating expenses	2,985,757	3,069,548	3,147,038
Operating profit	176,101	176,208	1,778,955
Other income (expenses):			
Interest income	360	478	1,838
Interest expense	(36,361)	(33,082)	(81,961)
Net other expense	(36,001)	(32,604)	(80,123)
Earnings before provision for income taxes	140,100	143,604	1,698,832
Income tax expense (benefit):			
Current	(25,502)	25,502	539,048
Deferred	9,906	(282,737)	(10,786)
	(15,596)	(257,235)	528,262
Net income	$155,696	$400,839	$1,170,570
Earnings per common share:			
Basic:	$0.08	$0.21	$0.63
Diluted:	$0.08	$0.21	$0.61
Weighted average common shares outstanding:			
Basic:	1,947,605	1,888,070	1,846,394
Diluted:	1,962,656	1,929,588	1,934,235

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
(Unaudited)

	Common Stock Par Value	Treasury Stock	Additional Paid-In Capital	Retained Earnings	Total Stockholders' Equity
Balance at 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 at March 31, 2009	$ 981,308	$ (426,617)	$ 5,617,620	$ 4,755,299	$ 10,927,610
Net income	-	-	-	400,839	400,839
Issuance of stock through options exercised	20,625	-	238,747	-	259,372
Excess tax benefits from stock-based compensation	-	-	25,502	-	25,502
Stock based compensation	-	-	26,030	-	26,030
Balance at March 31, 2010	$ 1,001,933	$ (426,617)	$ 5,907,899	$ 5,156,138	$ 11,639,353
Net Income	-	-	-	155,696	155,696
Issuance of stock for properties	-	136,277	28,479	-	164,756
Purchase of stock	-	(12,325)	-	-	(12,325)
Issuance of stock through options exercised	42,625	-	491,000	-	533,625
Excess tax benefit from stock-based compensation	-	-	(25,502)	-	(25,502)
Stock based compensation	-	-	51,350	-	51,350
Balance at March 31, 2011	$ 1,044,558	$ (302,665)	$ 6,453,226	$ 5,311,834	$ 12,506,953

SHARE ACTIVITY

	2011	2010	2009
Common stock shares, issued:			
At beginning of year	2,003,866	1,962,616	1,841,366
Issued	85,250	41,250	121,250
At end of year	2,089,116	2,003,866	1,962,616
Common stock shares, held in treasury:			
At beginning of year	(84,000)	(84,000)	(84,000)
Exchange for property	26,833	-	-
Acquisitions	(2,000)	-	-
At end of year	(59,167)	(84,000)	(84,000)
Common stock shares, outstanding			
At end of year	2,029,949	1,919,866	1,878,616

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,

	2011	2010	2009
Cash flows from operating activities:			
Net income	$155,696	$400,839	$1,170,570
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax (benefit) expense	9,906	(282,737)	(10,786)
Excess tax (expense) benefit from share based payment Arrangement	25,502	(25,502)	(539,048)
Stock-based compensation	51,350	26,030	54,688
Depreciation, depletion and amortization	1,047,906	1,113,141	1,046,120
Accretion of asset retirement obligations	34,129	31,625	28,578
Other	(22,526)	(8,295)	(4,135)
Changes in assets and liabilities:			
Decrease (increase) in accounts receivable	186,157	(84,393)	355,960
Decrease (increase) in prepaid expenses	(47,318)	19,449	(14,548)
(Decrease) increase in income taxes payable	(25,502)	25,502	539,048
(Decrease) increase in accounts payable and accrued expenses	(79,840)	(52,508)	167,932
Net cash provided by operating activities	1,335,460	1,163,151	2,794,379
Cash flows from investing activities:			
Additions to oil and gas properties	(2,435,374)	(901,156)	(2,937,939)
Acquisition of business	(478,000)	-	-
Additions to other property and equipment	(2,359)	(14,800)	-
Proceeds from investment in GazTex, LLC	-	-	18,700
Proceeds from sale of oil and gas properties and equipment	3,107	104,787	2,538
Net cash used in investing activities	(2,912,626)	(811,169)	(2,916,701)
Cash flows from financing activities:			
Acquisition of treasury stock	(12,325)	-	-
Proceeds from exercise of stock options	533,625	259,372	703,240
Reduction of long-term debt	(1,395,000)	(775,000)	(2,849,521)
Proceeds from long-term debt	2,495,000	75,000	1,649,521
Excess tax (expense) benefit from share based payment arrangement	(25,502)	25,502	539,048
Net cash provided by (used in) financing activities	1,595,798	(415,126)	42,288
Net increase (decrease) in cash and cash equivalents	18,632	(63,144)	(80,034)
Cash and cash equivalents at beginning of period	160,439	223,583	303,617
Cash and cash equivalents at end of period	$179,071	$160,439	$223,583
Supplemental disclosure of cash flow information:			
Cash paid for interest	$35,738	$34,535	$89,490
Income taxes paid	$-	$-	$-

Non-cash investing and financing activities:			
Asset retirement obligations	$25,043	$20,599	$38,247
Issuance of common stock in exchange for oil and gas properties	$164,756	$-	$-
Percentage of royalty interest purchase issued as payment for finder's fee	$-	$-	$31,863
Acquisition of Southwest Texas Disposal Corporation resulting in the assumption of liabilities as follows:			
Fair value of assets	$487,868	$-	$-
Cash paid	(478,000)	$-	$-
Liabilities assumed	$9,868	$-	$-

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) and its wholly owned subsidiaries, Forman Energy Corporation (a New York corporation) and Southwest Texas Disposal Corporation (a Texas corporation) (collectively, the "Company") are engaged in the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids ("NGLs"). Most of the Company's oil and gas interests are centered in West Texas; however, we own producing properties and undeveloped acreage in twelve states. Although most of our oil and gas interests are operated by others, we operate several properties in which we own an interest.

On September 30, 2010, Mexco Energy Corporation acquired all of the issued and outstanding stock of Southwest Texas Disposal Corporation, a Texas corporation, which owns royalties producing primarily natural gas.

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, estimates and assumptions 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. In addition, significant estimates are used in determining year end proved oil and gas reserves. Although management believes its estimates and assumptions are reasonable, actual results may differ materially from those estimates. The estimate of our oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment of oil and gas properties, is the most significant of the estimates and assumptions that affect these reported results.

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. At March 31, 2011, we had the majority of our cash and cash equivalents with one financial institution. We have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk.

Accounts Receivable. Our accounts receivable include trade receivables from joint interest owners and oil and gas purchasers. Credit is extended based on an evaluation of a customer's financial condition and, generally, is uncollateralized. Accounts receivable under joint operating agreements have a right of offset against future oil and gas revenues if a producing well is completed. The collectability of receivables is assessed and an allowance is made for any doubtful accounts. The allowance for doubtful accounts is determined based on our previous loss history. We have not experienced any significant credit losses. For the years ending March 31, 2011 and 2010, no allowance has been made for doubtful accounts.

Oil and Gas Properties. Oil and gas properties are accounted for using the full cost method of accounting. Under this method of accounting, the costs of unsuccessful, as well as successful, acquisition, exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation (“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 depreciation, depletion and amortization (“DD&A”) pool). Impairments transferred to the DD&A pool increase the DD&A rate.

Accounting for Long-Lived Assets. The Company reviews property and equipment for impairment whenever indicators of impairment are present to determine if the carrying amounts exceed the estimated future net cash flows to be realized. Impairment losses are recognized based on the estimated fair value of the asset.

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 to determine 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; and, as of fiscal 2010, using an average price over the prior 12-month period held flat for the life of production plus the lower of cost or fair market value of unproved properties. Prior fiscal years used prices in effect on March 31, the end of our fiscal period. 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 as an expense reflected in additional accumulated DD&A. 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.

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. The Company recognizes deferred tax assets and liabilities for 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 is recognized in net income in the period that includes the enactment date. Any interest and penalties are recorded as interest expense and general and administrative expense, respectively.

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 three to ten years.

Income Per Common Share. Basic net income per share is computed by dividing net income by the weighted average number of common 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:

	2011	2010	2009
Net income	$155,696	$400,839	$1,170,570
Shares outstanding:			
Weighted avg. common shares outstanding – basic	1,947,605	1,888,070	1,846,394
Effect of the assumed exercise of dilutive stock options	15,051	41,518	87,841
Weighted avg. common shares outstanding – dilutive	1,962,656	1,929,588	1,934,235
Earnings per common share:			
Basic	$0.08	$0.21	$0.63
Diluted	$0.08	$0.21	$0.61

For the years ended March 31, 2011, 2010 and 2009, no potential common shares relating to stock options were excluded in the computation of diluted net income per share.

Revenue Recognition. 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.

Gas Balancing. 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 use the Binomial option pricing model to estimate the fair value of stock based compensation expenses at grant date. This expense 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.

Recent Accounting Pronouncements. In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting. The revised rules are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. In January 2010, the Financial Accounting Standards Board ("FASB") issued guidance that aligns the FASB's oil and gas reserve estimation and disclosure requirements with the new SEC rule revisions. The accounting standards revised the definition of proved reserves to permit consideration of new technologies in evaluating oil and natural gas reserves; require the use of an average price based on the prior twelve month period rather than year-end prices; permit the disclosure of probable and possible oil and gas reserves; require the reporting of the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates; and, revise the disclosure requirements for oil and gas operations. The final rules and new guidance are effective for fiscal years ending on or after December 31, 2009. Mexco adopted these requirements as of March 31, 2010 and the results of the adoption are contained herein.

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06, Fair Value Measurements and Disclosures (Topic 820). ASU No. 2010-06 amends Accounting Standards Codification ("ASC") Topic 820 with new guidance and clarifications for improving disclosures about fair value measurements. This guidance requires enhanced disclosures regarding transfers of assets and liabilities between Level 1 (quoted prices in active market for identical assets or liabilities) and Level 2 (significant other observable inputs) of the fair value measurement hierarchy, including the reasons and the timing of the transfers. Additionally, the guidance requires a roll forward of activities on purchases, sales, issuance, and settlements of the assets and liabilities measured using significant unobservable inputs (Level 3 fair value measurements). ASU No. 2010-06 became effective for the Company beginning January 1, 2010, except for the disclosure on the roll forward activities for Level 3 fair value measurements, which will become effective for the Company with the reporting period beginning April 1, 2011. Other than requiring additional disclosures, adoption of this new guidance did not have any effect on the financial statements.

In December 2010, the FASB issued ASU No. 2010-29, Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations. ASU No. 2010-29 amends ASC Topic 805 and reflects the decision reached in Emerging Issues Task Force ("EITF") Issue No. 10-G. The amendments in this ASU specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU No. 2010-29 becomes effective prospectively for the Company with the reporting period beginning April 1, 2011. The Company does not anticipate that adoption of this new guidance will have a material impact on its financial statements.

There were various other accounting standards and interpretations issued during our fiscal year, all of which have been determined to be not applicable or significant by management and once adopted are not expected to have a material impact on the Company's financial position, operations or cash flows.

3. Business Combinations and Property Acquisitions

On September 30, 2010, Mexco purchased all of the outstanding stock of Southwest Texas Disposal Corporation ("STDC"), a Texas corporation which owns primarily royalties producing primarily natural gas, expanding our royalty revenues. The cash purchase price of $478,000 was funded from our $4.9 million credit facility.

The purchase price was allocated to the assets acquired and liabilities assumed at estimated fair values as follows:

Proved oil and gas properties	$477,018	
Accounts receivable	10,850	
Total assets acquired	487,868	
Accounts payable	(7,850	)
Asset retirement obligations assumed	(2,018	)
Net purchase price	$478,000	

We have not disclosed the pro forma information for this acquisition because the revenue and expenses for this acquisition are immaterial to our consolidated financial statements.

In August 2010, we purchased overriding royalty interests averaging .28% in approximately 5,120 gross acres covering eight sections in the Haynesville trend area of DeSoto Parish, Louisiana, for an approximate purchase price of $1.65 million. The Company paid $1.46 million in cash and the remainder was paid as 26,833 shares of its common stock issued from treasury shares.

4. Fair Value of Financial Instruments.

Fair value as defined by authoritative literature is the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1 – Quoted prices in active markets for identical assets and liabilities.

Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 – Significant inputs to the valuation model are unobservable.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. In accordance with the reporting requirements of FASB ASC Topic 825, Financial Instruments, the Company calculates the fair value of its assets and liabilities which qualify as financial instruments.

The initial measurement of asset retirement obligations' fair value is calculated using discounted cash flow techniques and is based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the ARO liability is deemed to use Level 3 inputs. See the Company's note on AROs for further discussion. AROs incurred during the year ended March 31, 2011 were approximately $25,000.

The carrying amount reported in the accompanying consolidated balance sheets for cash and cash equivalents, accounts receivable and accounts payable and accrued expenses approximates fair value because of the immediate or short-term maturity of these financial instruments. The carrying amount reported in the accompanying consolidated balance sheets for long term debt approximates fair value because the actual interest rates do not significantly differ from current rates offered for instruments with similar characteristics.

5. Credit Facility

As of October 22, 2010, Mexco has a revolving credit agreement with Bank of America, N.A. (the "Agreement"), which provides for a credit facility of $4,900,000 with no monthly commitment reductions and a borrowing base evaluated annually set at $4,900,000. Amounts borrowed under the Agreement are collateralized by the common stock of one of the Company's wholly owned subsidiaries and substantially all of the Company's oil and gas properties. Availability of this line of credit at March 31, 2011 was $3,100,000. No principal payments are anticipated to be required through November 30, 2012.

The Agreement was renewed four times with fourth amendment on October 22, 2010, which revised the maturity date to November 30, 2012. Under the original and renewed agreements, interest on the facility accrues at an annual rate equal to the British Bankers Association London Interbank Offered Rate ("BBA LIBOR") daily floating rate, plus 2.50 percentage points, which was 2.75% on March 31, 2011. Interest on the outstanding amount under the credit agreement is payable monthly. In addition, the Company will pay an unused commitment fee in an amount equal to ½ of 1 percent (.5%) times the daily average of the unadvanced amount of the commitment. The unused commitment fee is payable quarterly in arrears on the last day of each calendar quarter.

The 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 Agreement. Mexco is in compliance with all covenants as of March 31, 2011. In addition, this Agreement prohibits us from paying cash dividends on our common stock.

At the end of fiscal 2011, a letter of credit for $50,000, in lieu of a plugging bond with the Texas Railroad Commission covering the properties the Company operates is also outstanding under the facility. This letter of credit renews annually.

The balance outstanding on the line of credit was $1,800,000 as of March 31, 2011 and $950,000 as of June 28, 2011.

6. Asset Retirement Obligations

Mexco's asset retirement obligations relate to the plugging of wells, the removal of facilities and equipment, and site restoration on oil and gas properties. The fair value of a liability for an ARO is recorded in the period in which it is incurred, discounted to its present value using the credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset.

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

	2011	2010
Carrying amount of asset retirement obligations as of April 1	$536,305	$490,011
Liabilities incurred	25,043	20,599
Liabilities settled	(16,566)	(5,930)
Accretion expense	34,129	31,625
Carrying amount of asset retirement obligations as of March 31	578,911	536,305
Less: Current portion	50,000	50,000
Non-Current asset retirement obligation	$528,911	$486,305

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

7. Income Taxes

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

	2011	2010	2009
Deferred tax assets:			
Percentage depletion carryforwards	$1,180,896	$1,124,820	$839,900
Deferred stock-based compensation	2,872	7,536	31,468
Asset retirement obligation	179,462	166,255	151,903
Net operating loss	125,848	-	29,387
Other	6,200	7,311	4,692
	1,495,278	1,305,922	1,057,350
Deferred tax liabilities:			
Excess financial accounting bases over tax bases of property and equipment	(2,407,941)	(2,208,679)	(2,242,844)
Net deferred tax liabilities	$(912,663)	$(902,757)	$(1,185,494)

As of March 31, 2011, we have a statutory depletion carryforward of approximately $3,809,000, which does not expire. At March 31, 2011, we had a net operating loss carryforward for regular income tax reporting purposes of approximately $2,567,000, 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.

Mexco files income tax returns in the U.S. federal jurisdiction and various state jurisdictions. The amount of income taxes we record requires the interpretation of complex rules and regulations of federal and state taxing jurisdictions. With few exceptions, Mexco is no longer subject to U.S. federal and state income tax examinations by tax authorities for years prior to 2006.

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

	2011	2010	2009
Tax expense at statutory rate	$47,634	$48,825	$577,603
Statutory depletion carryforward	(86,221)	(127,253)	(34,100)
Effect of graduated rates	(3,074)	1,271	(3,885)
Revision of prior year estimates	44,503	(171,736)	(16,833)
Permanent differences	(17,309)	5,319	10,598
Other	(1,129)	(13,661)	(5,121)
	$(15,596)	$(257,235)	$528,262
Effective tax rate	(11%)	(179%)	31%

For the year ended March 31, 2011, there was a current income tax benefit of $25,502 and a deferred income tax expense of $9,906. For the year ended March 31, 2010, current income tax expense was $25,502 and deferred income tax was a benefit of $282,737. For the year ended March 31, 2009, current income tax expense was $539,048 and deferred income tax was a benefit of $10,786.

For the years ended March 31, 2011, 2010 and 2009, we did not have any uncertain tax positions.

For the years ended March 31, 2011 and 2010, the amount of unrecognized tax benefits was approximately $670,000 and $524,000, respectively. While it is expected the amount of unrecognized tax benefits will change in the next 12 months, we do not expect any change to have a significant impact on our results of operations. The recognition of the total amount of the unrecognized tax benefits of $670,000 would have an impact on the effective tax rate. If these unrecognized tax benefits are disallowed, we will be required to pay additional taxes.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	2011	2010	2009
Unrecognized tax benefits at beginning of period	$524,000	$549,000	$-
Additions based on tax positions related to the current year	146,000	-	1,029,000
Reductions for tax positions of prior years	-	-	-
Settlements	-	25,000	480,000
Expirations	-	-	-
Unrecognized tax benefits at end of period	$670,000	$524,000	$549,000

8. 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 2011, two customers accounted for 28% of the total revenues. In fiscal 2010 and 2009, two customers accounted for 32% of our total revenues. At March 31, 2011, 2010 and 2009, accounts receivable from these customers combined were approximately 25%, 23% and 16% of oil and gas accounts receivable, respectively.

9. Oil and Gas Costs

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

	2011	2010	2009
Property acquisition costs:			
Proved	$2,147,892	$80,154	$1,682,374
Unproved	-	-	-
Exploration	29,292	22,246	615,073
Development	394,381	596,660	456,799
Capitalized asset retirement obligations	25,043	20,599	38,247
Total costs incurred for oil and gas properties	$2,596,608	$719,659	$2,792,493

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

	2011	2010	2009
Proved oil and gas properties	$30,256,330	$27,182,529	$26,565,291
Unproved oil and gas properties:			
subject to amortization	170,487	170,487	170,487
not subject to amortization	-	-	-
	30,426,817	27,353,016	26,735,778
Less accumulated DD&A	15,161,524	14,119,129	13,013,448
	$15,265,293	$13,233,887	$13,722,330

DD&A amounted to $1.87, $1.70 and $1.62 per equivalent mcf of production for the years ended March 31, 2011, 2010 and 2009, respectively.

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10. Stockholders' Equity

In June 2010, the board of directors authorized the use of up to $250,000 to repurchase shares of our common stock for the treasury account. During fiscal 2011, we repurchased 2,000 shares at a cost of $12,325. No shares of our common stock were repurchased for the treasury account during fiscal 2010 and 2009.

In August 2010, we purchased overriding royalty interests averaging .28% in 5,120 gross acres covering eight sections in the Haynesville trend area of DeSoto Parish, Louisiana, for an approximate purchase price of $1.65 million, prior to closing adjustments. We paid $1.46 million in cash and the remainder was paid as 26,833 shares of its common stock issued from treasury shares.

11. Stock Options

We adopted an employee incentive stock plan effective September 15, 1997 ("1997 Plan"). Under the 1997 Plan, 350,000 shares were 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 was at least $5.00 per share of restricted stock. The awards of restricted stock must be accepted within 60 days and 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 ("2004 Plan") to replace, modify and extend the termination date of the 1997 Plan to September 14, 2009. The 2004 Plan provided for the award of stock options up to 375,000 shares of which 125,000 may have been 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 were similar to those of the 1997 Plan except that the term of the options was five years from the date of grant. Although shares were remaining unissued at the termination date of the 2004 Plan, the shares are no longer eligible to be granted.

In September 2009, we adopted the 2009 Employee Incentive Stock Plan ("2009 Plan") to replace the 1997 and 2004 Plans. The 2009 Plan provides for the award of stock options up to 200,000 shares and includes option awards as well as stock awards. Option awards are granted with the restriction of requiring payment for the shares. Stock awards are granted without restrictions and without payment by the recipient. Neither option awards nor stock awards may exceed 25,000 shares granted to any one individual in any fiscal year. The 2009 Plan expires ten years from the date of 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 plans also provide for the granting of stock awards. No stock awards were granted during fiscal 2011, 2010 and 2009.

We recognized compensation expense of $51,350, $26,030 and $54,688 in general and administrative expense in the Consolidated Statements of Operations for fiscal 2011, 2010 and 2009, respectively. The total cost related to non-vested awards not yet recognized at March 31, 2011 totals $142,569, which is expected to be recognized over a weighted average of 3.2 years.

For the year ended March 31, 2011, employees and directors exercised options on a total of 85,250 shares at exercise prices between $4.00 and $8.24 per share. The Company received proceeds of $533,625 from these exercises. The total intrinsic value of the exercised options was $533,831. Of these exercised options, 29,950 shares resulted in a disqualifying disposition. No tax deduction is recorded when options are awarded. Mexco issued new shares of common stock to settle these option exercises. For the year ended March 31, 2010, stock options covering 41,250 shares were exercised and 4,750 of these exercised options resulted in a disqualifying disposition. For the year ended March 31, 2009, stock options covering 45,750 shares were exercised and resulted in a disqualifying disposition.

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 84 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.

During the year ended March 31, 2011, stock options covering 42,500 shares were granted. No stock options were granted during the year ended March 31, 2010 and 2009.

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 2011, 2010 and 2009. All such amounts represent the weighted average amounts for each period.

	For the year ended March 31,		
	2011	2010	2009
Grant-date fair value	$ 5.15	-	-
Volatility factor	82.83%	-	-
Dividend yield	-	-	-
Risk-free interest rate	2.07%	-	-
Expected term (in years)	7	-	-

Stock options covering 85,250 shares were exercised during the year ended March 31, 2011. Stock options covering 41,250 shares were exercised during the year ended March 31, 2010 and 121,250 shares were exercised during the year ended March 31, 2009.

Cash received from option exercise under all share-based payment arrangements for the years ended March 31, 2011, 2010 and 2009, was $533,625, $259,372 and $703,240, respectively.

No forfeiture rate is assumed for stock options granted to directors or employees due to the forfeiture rate history for these types of awards. During the year ended March 31, 2011, 1,000 vested stock options expired because they were not exercised prior to the end of their ten-year term and 10,000 unvested stock options were forfeited due to the termination of a consulting agreement with a consultant and the resignation of an employee. There were no stock options forfeited or expired during the year ended March 31, 2010. During the year ended March 31, 2009, 20,000 stock options expired because they were not exercised prior to the end of their ten-year term.

The following table is a summary of activity of stock options for the year ended March 31, 2011 and 2010:

	Number of Shares	Weighted Average Exercise Price Per Share	Weighted Aggregate Average Remaining Contract Life in Years	Intrinsic Value
Outstanding at March 31, 2009	148,750	$6.04	3.04	$813,703
Granted	-	-		

Exercised	(41,250)	6.29		
Forfeited or Expired	-	-		
Outstanding at March 31, 2010	107,500	$5.94	2.51	$237,088
Granted	42,500	6.24		
Exercised	(85,250)	6.26		
Forfeited or Expired	(11,000)	5.89		
Outstanding at March 31, 2011	53,750	$5.69	7.33	$401,200
Vested at March 31, 2011	10,000	$4.00	1.16	$91,500
Exercisable at March 31, 2011	10,000	$4.00	1.16	$91,500

Outstanding options at March 31, 2011 expire between May 2012 and September 2020 and have exercise prices ranging from $4.00 to $6.29.

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

	2011	2010	2009
Weighted average grant-date fair value of stock options granted (per share)	$5.15	-	$-
Total fair value of options vested	$37,200	$343,663	$82,225
Total intrinsic value of options exercised	$533,831	$130,051	$4,209,381

The following table summarizes information about options outstanding at March 31, 2011:

Range of Exercise Prices	Number of Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contract Life in Years	Aggregate Intrinsic Value
$4.00 – 5.24	13,750	$4.10		
5.25 – 6.29	40,000	6.23		
$4.00 – 6.29	53,750	$5.69	7.33	$401,200

12. Related Party Transactions

Related party transactions for the fiscal year ended March 31, 2011 relate to shared office expenditures in addition to administrative and operating expenses paid on behalf of the majority stockholder. The totals billed to and reimbursed by the stockholder for the years ended March 31, 2011, 2010 and 2009 were $ 137,652, $75,178 and $40,872, 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, on the same basis as an unrelated third party investor, in a 5.0% working interest in our well in Ward County, Texas. Effective January 1, 2010, we purchased Mr. Craddick’s 5.0% working interest in this well for a purchase price of approximately $78,000. Mr. Craddick maintained a .125% override in this well. Revenues paid to Mr. Craddick from this well were $100 and $3,360 for the years ended March 31, 2011 and 2010, respectively.

In September 2009, Jeff Smith, a geological consultant, entered into an amended agreement with Mexco to provide geological consulting services for a fee of approximately $500 per month plus expenses. This agreement was subsequently terminated in January 2010 thus Mr. Smith is no longer considered a related party for transactions for the year ended March 31, 2011. Mexco incurred charges from Mr. Smith of $24,750 for the year ended March 31, 2010. Also as part of this agreement, Mr. Smith received 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 our 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. Revenues paid to Mr. Smith from these wells were $4,590 for the year ended March 31, 2010. At March 31, 2010, Mr. Smith had a balance due of $55 for his share of the expenses on these wells, which was reflected in accounts receivable — related parties.

13. 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. The estimates as of March 31, 2011, 2010, and 2009 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:

	2011		2010		2009	
	Bbls	Mcf	Bbls	Mcf	Bbls	Mcf
Proved reserves, beginning of year	240,000	8,405,000	207,000	9,477,000	217,000	7,857,000
Revision of previous estimates	22,000	130,000	39,000	(575,000)	(24,000)	140,000
Purchase of minerals in place	45,000	545,000	-	5,000	-	886,000
Extensions and discoveries	-	136,000	12,000	44,000	31,000	1,136,000
Sales of minerals in place	-	-	-	-	-	-
Production	(17,000)	(459,000)	(18,000)	(546,000)	(17,000)	(542,000)
Proved reserves, end of year	290,000	8,757,000	240,000	8,405,000	207,000	9,477,000

Summary of Proved Reserves as of March 31, 2011:

	Oil (Bbls)	Natural Gas (Mcf)	Oil & Natural Gas (Mcfe)
Developed	159,975	4,964,061	5,923,911
Undeveloped	130,187	3,792,974	4,574,096
Total proved reserves	290,162	8,757,035	10,498,007

At March 31, 2011, we reported estimated PUDs of 4.6 bcfe, which accounted for 44% of our total estimated proved oil and gas reserves. This figure primarily consists of a projected 23 new wells (3.4 bcfe), 6 of which we operate, and 1 new zone behind pipe from a currently producing wellbore (.1 bcfe) that we also operate. Our timetable for this well is totally dependent on the life of the currently producing zone. After the current zone has depleted, we will open the new productive zone. Of the 6 wells we operate (2.7 bcfe), 5 have additional productive zones behind pipe (.6 bcfe). We project 1 operated well to be drilled in fiscal 2012, 4 in fiscal 2013 and 1 in fiscal 2014. The behind pipe zones can only come on after the current producing zones are depleted. Also, there is potential to commingle the new zones in the new wells with prior permission from the Railroad Commission. Regarding the remaining 17 PUD locations operated by others (.6 bcfe), a location is currently being prepared to drill 1 well with plans for a second well to follow, 5 wells in 2012, 6 in 2013 and 4 in 2014.

Included in proved undeveloped reserves at March 31, 2011 are approximately 2.7 bcfe of material reserves which have remained undeveloped for more than five years. These primarily consist of three drilling locations in an area where we have long-standing operations. These locations are currently held by production from other wells in which Mexco owns. During fiscal years 2009 through 2010, we were reasonably certain that we would drill wells associated with these PUDs within the next five years; however, we were given the opportunity to participate in, or operate wells, that were not held by production, were not planned and presented themselves to the Company with a short amount of time to commit. We were not the operator of some of the opportunities in which we were able to participate. Other projects that arose were presented to the Company as an operator and we were able to collect a prospect fee and participate with a partial carried interest financed by others. A portion of our capital was allocated to non-operated working interests where failure to participate would cause a forfeiture in preference to developing reserves in which we were the operator and no forfeiture would result from deferring development. Our timetable for the three new wells is to drill one per year over the next three years beginning in fiscal 2012.

The following table discloses our progress toward the conversion of PUDs during 2011.

Progress of Converting Proved Undeveloped Reserves:

	Oil & Natural Gas (Mcfe)	Future Development Costs
PUDs, beginning of year	3,976,777	$2,982,205
Revision of previous estimates	36,180	116,667
Conversions to PD reserves	(53,603)	(10,882)
Additional PUDs added	614,742	657,840
PUDs, end of year	4,574,096	$3,745,830

In December 2008, the SEC issued its final rule, Modernization of Oil and Gas Reporting, which is effective for reporting reserve information for fiscal years ending December 2009. In January 2010, the FASB issued its authoritative guidance on extractive activities for oil and gas to align its requirements with the SEC's final rule. We adopted the guidance as of March 31, 2010 in conjunction with our year-end reserve report as a change in accounting principle that is inseparable from a change in accounting estimate. Under the SEC's final rule, prior period reserves were not restated.

The new reporting rules require that year end reserve calculations and future cash inflows be based on the 12-month average market prices for sales of oil and gas on the first calendar day of each month during the fiscal year discounted at 10% per year and assuming continuation of existing economic conditions. The average prices used for fiscal 2011 were $77.27 per bbl of oil and $3.88 per mcf of natural gas. The average prices used for fiscal 2010 were $66.21 per bbl of oil and $3.77 per mcf of natural gas. Prices used for fiscal 2009 were $42.12 per bbl of oil and $3.13 per mcf of natural gas based on the year end weighted average prices of oil and natural gas, the oil and gas disclosure requirements effective during that period.

If we had used the March 31, 2010 prices in our fiscal 2010 calculations as in previous years, our total reserves would have decreased 52,000 Mcfe. This decrease in reserves would have had an effect on our DD&A and net income for the fourth quarter of 2010. The effect on DD&A was an increase of approximately $5,500 and a decrease in net income of approximately $3,800.

The following is a standardized measure of the discounted net future cash flows and changes applicable to proved oil and gas reserves presented pursuant to ASC 932. Future price changes were considered to the extent provided by contractual arrangements in existence at year end. Future development and production costs were computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year end costs. Future income tax expenses were computed by applying the year end statutory tax rates with consideration of future tax rates already legislated as well as tax credits and allowances relating to our proved oil and gas reserves to the future pre-tax net cash flows relating to our proved oil and gas reserves.

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 an independent petroleum engineering consultant, 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.

The standardized measure of discounted future cash flows at March 31, 2011, 2010 and 2009, which represents the present value of estimated future cash flows using a discount rate of 10% a year, follows:

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

	March 31		
	2011	2010	2009
Future cash inflows	$56,413,000	$47,638,000	$38,369,000
Future production costs and taxes	(11,086,000)	(10,101,000)	(8,182,000)
Future development costs	(4,029,000)	(3,265,000)	(3,384,000)
Future income taxes (a)	(9,118,000)	(7,439,000)	(5,306,000)
Future net cash flows	32,180,000	26,833,000	21,497,000
Annual 10% discount for estimated timing of cash flows	(14,528,000)	(12,673,000)	(9,989,000)

Standardized measure of discounted future net cash flows	$17,652,000	$14,160,000	$11,508,000

(a) Future income taxes are computed using effective tax rates on future net cash flows beforeincometaxes 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		
	2011	2010	2009
Sales of oil and gas produced, net of production costs	$(2,119,000)	$(2,167,000)	$(3,681,000)
Net changes in price and production costs	1,590,000	4,287,000	(27,213,000)
Changes in previously estimated development costs	830,000	(35,000)	1,116,000
Revisions of quantity estimates	1,088,000	397,000	(324,000)
Net change due to purchases and sales of minerals in place	1,976,000	11,000	1,572,000
Extensions and discoveries, less related costs	165,000	345,000	1,931,000
Net change in income taxes	(1,076,000)	(1,085,000)	3,124,000
Accretion of discount	1,809,000	1,435,000	4,090,000
Changes in timing of estimated cash flows and other	(771,000)	(536,000)	(1,605,000)
Changes in standardized measure	3,492,000	2,652,000	(20,990,000)
Standardized measure, beginning of year	14,160,000	11,508,000	32,498,000
Standardized measure, end of year	$17,652,000	$14,160,000	$11,508,000

14. Selected Quarterly Financial Data (Unaudited)

	FISCAL 2011			
	4th QTR	3rd QTR	2nd QTR	1st QTR
Oil and gas revenue	$776,469	$752,778	$783,990	$832,010
Operating profit (loss)	88,177	68,100	59,722	(39,898)
Net income	52,982	26,898	70,040	5,776
Net income per share – basic	.03	0.01	0.04	0.00
Net income per share – diluted	.03	0.01	0.04	0.00

	FISCAL 2010			
	4th QTR	3rd QTR	2nd QTR	1st QTR
Oil and gas revenue	$971,974	$857,035	$737,944	$653,810
Operating profit (loss)	129,931	136,585	(4,137)	(86,171)
Net income (loss)	143,347	167,145	158,350	(68,003)
Net income (loss) per share – basic	.07	0.09	0.08	(0.04)
Net income (loss) per share – diluted	.07	0.09	0.08	(0.04)

15. Subsequent Events

The Company completed a review and analysis of all events that occurred after the balance sheet date to determine if any such events must be reported and has determined that there are no subsequent events to be disclosed.

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
10.4*****	2009 Employee Incentive Stock Plan
14.1******	Code of Business Conduct and Ethics
21	Subsidiaries of the Company
23.1	Consent of Independent Registered Public Accounting Firm
23.2	Consent of Independent Petroleum Engineers
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.
99.1	Report of Joe C. Neal & Associates, Independent Petroleum Engineer

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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 Proxy Statement filed July 16, 2009.
****** Filed with the Company's Quarterly Report on Form 10-Q filed on November 15, 2004.

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