MEXCO ENERGY CORP
Form 10-K
June 27, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended March 31, 2018

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

Commission File No. 1-31785

MEXCO ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Colorado	**84-0627918**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

415 W. Wall, Suite 475	
Midland, Texas	**79701**
(Address of principal executive offices)	(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 per share**

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

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 [X]

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 [X] 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 [X] 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 [X]

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

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of September 30, 2017 (the last business day of the Registrant's most recently completed second quarter) was $3,827,675 based on Mexco Energy Corporation's closing common stock price of $4.45 per share on that date as reported by the NYSE American.

There were 2,037,266 shares of the registrant's common stock outstanding as of June 26, 2018.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement relating to the 2018 Annual Meeting of Shareholders to be held on September 11, 2018, 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, 2018, 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 exploration, development and production of crude oil and natural 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.

Our total estimated proved reserves at March 31, 2018 were approximately 2.111 million barrels of oil equivalent ("MMBOE") of which 57% was oil and natural gas liquids and 43% was natural gas, and our estimated present value of proved reserves was approximately $22 million based on estimated future net revenues excluding taxes discounted at 10% per annum, pricing and other assumptions set forth in "Item 2 – Properties" below. During fiscal 2018, we added proved reserves of 142 thousand BOE ("MBOE") through extensions and discoveries, subtracted 178 MBOE through sales of oil and gas properties and downward revisions of previous estimates of 1,003 MBOE. Such downward revisions are primarily the result of the restructuring of our plans for development of a non-producing leasehold interest in Martin County, Texas located in the Eastern Permian Basin due to market conditions partially offset by pricing and successful development in the Delaware and Midland Basins.

Nicholas C. Taylor beneficially owns approximately 46% of the outstanding shares of our common stock. Mr. Taylor is also our Chairman of the Board 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 especially seek to acquire proved reserves that fit well with existing operations or in areas where Mexco 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 2019.

While we own oil and gas properties in other states, the majority of our activities are centered in the Permian Basin of West Texas. The Company also owns producing properties and undeveloped acreage in thirteen states. 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. Most of the Company's oil and gas interests are operated by others, however the Company operates several properties in which it owns an interest.

From 1983 to 2018, Mexco Energy Corporation made approximately 80 acquisitions of producing oil and gas properties including royalties, overriding royalties, minerals and working interests both operated and non-operated plus the following most significant and recent acquisitions:

1993-2010	Tabbs Bay Oil Company and Thompson Brothers Lumber Company, respectively dissolved in 1957 and 1947. Purchase covering thousands of acres located respectively in 19 counties of Texas, 3 parishes of Louisiana and one county in Arkansas and 8 counties of Texas, respectively consisting of various mineral, royalty and overriding royalty interests.
1997	Forman Energy Corporation, purchase price of $1,591,000 consisting of primarily working interests in approximately 634 wells located in 12 states.
2010	Southwest Texas Disposal Corporation, purchase price $478,000 consisting of royalty interests in over 300 wells located in 60 counties and parishes of 6 states.
2012	TBO Oil and Gas, LLC, purchase price of $1,150,000 consisting of working interests in approximately 280 wells located in 16 counties of 3 states.

2014 Royalty interests, purchase price of $200,000 covering 43 wells in 12 counties of eight states. Of these oil and gas reserves, approximately 54% are in TX and 10% in LA.

Royalty interests, purchase price $580,000 covering 580 wells in 87 counties of eight states. Approximately 90% of the net revenue from these royalties is produced by 157 wells located in the Barnett Shale of the Fort Worth Basin of Texas. Also included are interests in 423 wells in 8 states.

Non-Operated working interests, purchase price $525,000 for 12.5% (approximately 10% net revenue interest). The purchase included eight wells producing oil on 20-acre spacing at approximately 3,600 foot depth on 190 acres in Pecos County, TX.

Royalty and mineral interests, purchase price $1,000,000 covering approximately 1,800 wells in 27 counties of Texas. Of these oil and gas reserves, approximately 80% is natural gas and 20% oil.

Non-Operated working interests, purchase price $840,000 in 70 Natural gas producing wells located in 5 counties of Oklahoma.

Industry Environment and Outlook

The challenging commodity price environment continued in fiscal 2018. Commodity prices improved but continue to be volatile. In light of these challenges facing our industry and in response to the continued challenging environment, our primary business strategies for fiscal 2019 will continue to include: (1) optimizing cash flows through operating efficiencies and cost reductions, (2) divesting of non-core assets, and (3) working to balance capital spending with cash flows to minimize borrowings, reduce debt and maintain ample liquidity.

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for discussion of our fiscal 2018 operating results and potential impact on fiscal 2019 operating results due to commodity price changes.

Oil and Gas Operations

As of March 31, 2018, oil constituted approximately 57% of our total proved reserves and approximately 68% of our revenues for fiscal 2018. Revenues from oil and gas royalty interests accounted for approximately 21% of our revenues for fiscal 2018.

There are two primary areas in which the Company is focused, 1) the Delaware Basin located in the Western portion of the Permian Basin including Lea and Eddy Counties, New Mexico and Loving County, Texas and 2) the Midland Basin located in the Eastern portion of the Permian Basin including Reagan, Upton, Midland, Martin, Howard and Glasscock Counties, Texas. The Permian Basin in total accounts for 72% of our discounted future net cash flows from proved reserves and 64% of our net revenues.

The Delaware Basin properties, encompassing 31,604 gross acres, 528 net acres, 473 gross producing wells and 5 net wells account for approximately 37% of our discounted future net cash flows from proved reserves as of March 31, 2018. Of these discounted future net cash flows from proved reserves, approximately 11% are attributable to proven undeveloped reserves which will be developed through new drilling. For fiscal 2018, these properties accounted for 35% of our gross revenues and 44% of our net revenues.

The Midland Basin properties, encompassing 90,148 gross acres, 268 net acres, 650 gross producing wells and 3 net wells account for approximately 35% of our discounted future net cash flows from proved reserves as of March 31, 2018. Of these discounted future net cash flows from proved reserves, approximately 29% are attributable to proven undeveloped reserves which will be developed through new drilling. For fiscal 2018, these properties accounted for

18% of our gross revenues and 19% of our net revenues.

Gomez Gas Field properties, encompassing 13,058 gross acres, 72 net acres, 26 gross wells and .13 net wells in Pecos County, Texas, account for approximately 2% of our discounted future net cash flows from proved reserves as of March 31, 2018. For fiscal 2018, these properties accounted for 2% of our gross revenues and 3% of our net revenues. All of these properties, except for one, are royalty interests. There is a potential for development of the horizontal Wolfcamp on these interests.

The Goldsmith North Field (San Andres formation) long-lived oil producing properties, encompassing 160 gross acres, 123 net acres, 3 gross wells in Ector County, Texas, account for 9% of our discounted future net cash flows from proved reserves as of March 31, 2018. Of these discounted future net cash flows from proved reserves, 8% are attributable to proven undeveloped reserves which will be developed through new drilling of 4 wells. For fiscal 2018, these properties consist of working interests and accounted for 4% of our gross revenues and 2.2% of our net revenues. There is potential for further development of this property by horizontal drilling.

Mexco believes its most important properties for future development by horizontal drilling and hydraulic fracturing area are located in Midland, Reagan and Upton Counties, Texas of the Midland Basin and the Delaware Basin in Lea and Eddy Counties, New Mexico and Loving County, Texas.

For more on these and other operations in this area see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources Commitments”.

We own partial interests in approximately 6,000 producing wells all of which are located within the United States in the states of Texas, New Mexico, Oklahoma, Louisiana, Alabama, Mississippi, Arkansas, Wyoming, Kansas, Colorado, Montana, Virginia and North Dakota. We own interests in and operate 3 producing wells. We divested working interests in 2 producing wells located in Loving County, Texas in January 2018 (see Oil and Natural Gas Property Transactions under Item 7 of this report for further details). 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:

Year	Oil(Bbls)	Gas (Mcf)
2018	34,743	318,774
2017	34,689	356,268
2016	38,930	407,939
2015	29,557	369,034
2014	27,186	361,652

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

	2018		2017	
Company A	37	%	31	%
Company B	8	%	12	%

Historically, the Company has not experienced significant credit losses on our oil and gas accounts and management is of the opinion that significant credit risk does not exist. 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.

Environmental Regulation

General. Activities on the Company properties are subject to existing stringent and complex federal, state and local laws (including case law) and regulations governing health, safety, environmental quality and pollution control. Failure to comply with these laws, rules and regulations, however, may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of the operations on the Company properties.

Cleanup. Under certain environmental laws and regulations, the operators of the Company properties could be subject to strict, joint and several liability for the removal or remediation of property contamination, whether at a drill site or a waste disposal facility, even when the operators did not cause the contamination or their activities were in compliance with all applicable laws at the time the actions were taken. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "superfund" law, for example, imposes liability, regardless of fault or the legality of the original conduct, on certain classes of persons for releases into the environment of a "hazardous substance." Liable persons may include the current or previous owner and operator of a site where a hazardous substance has been disposed and persons who arranged for the disposal of a hazardous substance at a site. Under CERCLA and similar statutes, government authorities or private parties may take actions in response to threats to the public health or the environment or sue responsible persons for the associated costs. In the course of operations, the working interest owner and/or the operator of the Company properties may have generated and may generate materials that could trigger cleanup liabilities. In addition, the Company properties have produced oil and/or natural gas for many years, and previous operators may have disposed or released hydrocarbons, wastes or hazardous substances at the Company properties. The operator of the Company properties or the working interest owners may be responsible for all or part of the costs to clean up any such contamination. Although the Company is not the operator of such properties, its ownership of the properties could cause it to be responsible for all or part of such costs to the extent CERCLA or any similar statute imposes responsibility on such parties as "owners."

Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and certain other greenhouse gases ("GHGs") endanger public health and the environment because emissions of such gases are contributing to warming of the Earth's atmosphere and other climatic changes. Based on those findings, the EPA adopted and implemented various regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act ("CAA"). Among other things, these covered reductions in GHG emissions from motor vehicles, permits for certain large stationary sources of GHGs, monitoring and annual reporting of GHG emissions from specified GHG emission sources, including oil and natural gas exploration and production operations, and power plant performance standards that were intended to lead to the creation of additional state GHG control programs. In June 2013, moreover, President Obama unveiled a Presidential climate action plan designed to reduce emissions in the US of methane, carbon dioxide and other GHGs. In furtherance of that plan, the Obama Administration launched a number of initiatives, including a Strategy to Reduce Methane Emissions from the oil and natural gas industry. The Obama Administration's goal was to reduce methane emissions from the oil and natural gas industry by 40-45% by 2025 as compared to 2012 levels. The EPA therefore issued regulations in 2016 that set additional standards for methane and volatile organic compound emissions from oil and natural gas production sources, including hydraulically fractured oil wells, and natural gas processing and transmission sources. As another prong of President Obama's methane strategy, the Bureau of Land Management promulgated standards for reducing venting and flaring on public lands. The Trump Administration has tried to delay or revise a number of the Obama-era regulations; however, proponents of climate change regulations have been challenging those efforts in various courts with some success to date. The direction of future U.S. climate change regulation therefore is difficult to predict. Federal agencies may or may not continue developing regulations to reduce GHG emissions from the oil and gas industry. Even if federal efforts in this area slow, states may continue pursuing climate regulations.

Various state governments and regional organizations comprising state governments already have enacted legislation and promulgated rules restricting GHG emissions or promoting the use of renewable energy, and additional such measures are frequently under consideration. Although it is not possible at this time to estimate how potential future requirements addressing GHG emissions would impact operations on the Company properties and revenue, either directly or indirectly, any future federal, state or local laws or implementing regulations that may be adopted to address GHG emissions could require the operators of our properties to incur new or increased costs to obtain permits, operate and maintain equipment and facilities, install new emission controls, acquire allowances to authorize GHG emissions, pay taxes related to GHG emissions or administer a GHG emissions program. Regulation of GHGs could also result in a reduction in demand for and production of oil and natural gas. Additionally, to the extent that unfavorable weather conditions are exacerbated by global climate change or otherwise, the Company properties may be adversely affected to a greater degree than previously experienced.

We did not incur any material capital expenditures for remediation or pollution control activities for the year ended March 31, 2018. 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 2019.

Title to 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.

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.

Substantially all of our properties are currently mortgaged under a deed of trust to secure funding through a 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, 2018.

Name	Age	Position
Nicholas C. Taylor	80	Chairman and Chief Executive Officer
Tamala L. McComic	49	President, Chief Financial Officer, Treasurer, and Assistant Secretary
Donna Gail Yanko	73	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 Chairman of the Board and Chief Executive Officer of the Company in September 2011 and continues to serve in such capacity on a part time basis, as required. He served as Chief Executive Officer, President and Director of the Company from 1983 to 2011. 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.

Tamala L. McComic, a Certified Public Accountant, became Controller for the Company in July 2001 and was elected President and Chief Financial Officer in September 2011. She served the Company as Executive Vice President and Chief Financial Officer from 2009 to 2011 and Vice President and Chief Financial Officer from 2003 to 2009. Prior thereto, Ms. McComic was appointed Treasurer and Assistant Secretary of the Company.

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 2015, on a part-time basis, she assisted the Chairman of the Board of the Company in his personal business activities. Ms. Yanko also served as a director of the Company from 1990 to 2008.

Employees

As of March 31, 2018, we had three 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. We also utilize the services of independent contractors to perform well drilling and production operations, including pumping, maintenance, inspection and testing.

Office Facilities

At March 31, 2018, our principal offices were located at 214 W. Texas Avenue, Suite 1101, Midland, Texas 79701. All of our leases for this location expired on April 1, 2018. As of May 15, 2018, our principal offices are located at 415 W. Wall, Suite 475, Midland, Texas 79701 and our telephone number is (432) 682-1119. On May 7, 2018, we agreed to a three year lease for our 4,160 square feet of office space. We believe our new facilities are adequate for our current operations and future needs.

Access to Company Reports

Mexco Energy Corporation files annual, quarterly and current reports, proxy statements and other information with the 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.

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 could have a material adverse effect on our business, financial position, liquidity and results of operations. Some of the following risks relate principally to the industry in which we operate and to our business. Other risks relate principally to the securities markets and ownership of our common stock.

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 and pricing of oil and gas; the ability of the Organization of Petroleum Exporting Countries ("OPEC") to set and maintain oil price and production controls; nature and extent of governmental regulation and taxation, including environmental regulations; level of domestic and international exploration, drilling and production activity; the cost of exploring for, producing and delivering oil and gas; speculative trading in crude oil and natural gas derivative contracts; availability, proximity and capacity of oil and gas pipelines and other transportation facilities; weather conditions; the price and availability of alternative fuels; technological advances affecting energy consumption; 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.

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 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.

Oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Lower prices or lack of storage may have an adverse affect on our financial condition due to reduction of our revenues, operating income and cash flows; curtailment or shut-in of our production due to lack of transportation or storage capacity; cause certain properties in our portfolio to become economically unviable; and, limit our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations.

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. We incurred impairment charges during fiscal 2016 and may incur additional impairment charges in the future, particularly if commodity prices decline, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. There were no ceiling test impairments on our oil and gas properties during fiscal 2018 and 2017.

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 hard to find.

Approximately 49% and 67% of our total estimated net proved reserves at March 31, 2018 and 2017, respectively, 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 or the outside operators of our properties 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.

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 2018, differentials averaged $0.69 per Bbl of oil and $0.03 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.

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.

Drilling and operating activities are high risk activities that subject us to a variety of factors that we cannot 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 our investment in wells drilled or re-entered.

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 credit facility to fund our capital expenditures, however, lower oil and gas prices may prevent these options. 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.

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.

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.

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

Our credit facility agreement requires us to comply with certain customary covenants including limitations on change of control, disposition of assets, mergers and reorganizations. We are also obligated to meet certain financial covenants. For example, our credit facility requires, among other things, minimum earnings before interest, taxes, depreciation and amortization (“EBITDA”) of $650,000 for each trailing four fiscal quarters and minimum interest coverage ratios (EBITDA/Interest Expense) of 2.00 to 1.00 for each quarter. If we fail to meet any of these loan covenants, the lender under the credit facility could accelerate the indebtedness and seek to foreclose on the pledged assets.

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

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

We 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.

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.

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

Legislation previously has been proposed that would, if enacted into law, make significant changes to U. S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to crude 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 crude 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 U.S. 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 and, if enacted, how soon any such changes could become effective. The passage of this type of legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to crude oil and natural gas exploration and development, and any such change could have an adverse effect on our financial position, results of operations and cash flows.

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 President and 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.

We may be affected by one substantial shareholder.

Nicholas C. Taylor beneficially owns approximately 46% of the outstanding shares of our common stock. Mr. Taylor is also our Chairman of the Board 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 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.

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.

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, 2018, our executive officers and directors beneficially owned approximately 51% 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 NYSE American. The market price of our common stock has and could continue to experience volatility due to reasons unrelated to our operating performance. These reasons include: supply and demand for natural gas and oil; political conditions in oil and natural gas producing regions; demand for our common stock and limited trading volume; investor perception of our industry; fluctuations in commodity prices; variations in our results of operations; legislative or regulatory changes; general trends in the oil and natural gas industry; market conditions and analysts' estimates; and, other events in the oil and gas industry.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock. We cannot assure you that the market price of our common stock will not fluctuate or decline significantly in the future. In addition, the stock markets in general can experience considerable price and volume fluctuations.

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, 2018, we had interests in approximately 6,000 gross (25 net) oil and gas wells and owned leasehold mineral and royalty interests in approximately 564,000 gross (3,732 net) acres.

Oil and Natural Gas Reserves

In accordance with current SEC rules, the average prices used in computing reserves at March 31, 2018 were $50.63 per bbl of oil and $43.88 in 2017, an increase of 15%, and $3.031 per mcf of natural gas and $2.561 in 2017, an increase of 18%, such prices are based on the 12-month unweighted arithmetic average market prices for sales of oil and natural gas on the first calendar day of each month during fiscal 2018. The benchmark price of $49.94 per bbl of oil at March 31, 2018 versus $44.10 at March 31, 2017, was adjusted by lease for gravity, transportation fees and regional price differentials and did not give effect to derivative transactions. The benchmark price of $3.00 per mcf of natural gas at March 31, 2018 versus $2.74 at March 31, 2017, was adjusted by lease for BTU content, transportation fees and regional price differentials.

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.

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.

The engineering report with respect to Mexco's estimates of proved oil and gas reserves as of March 31, 2018 is based on evaluations prepared by Russell K. Hall and Associates, Inc. Environmental Engineering Consultants, based in Midland, Texas ("Hall and Associates"), a summary of which is filed as Exhibit 99.1 to this annual report. The engineering report with respect to Mexco's estimates of proved oil and gas reserves as of March 31, 2017 was based on evaluations prepared by Joe C. Neal and Associates, Petroleum and Environmental Engineering Consultants, based in Midland, Texas.

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 Hall 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 20 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 Alan Neal, the technical person at Hall and Associates responsible for evaluating the proved reserves covered by this report. Mr. Neal is a member of the Society of Petroleum Engineers and has over 35 years of experience in the oil and gas industry. Our Chairman and Chief Executive Officer who has over 40 years of 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. 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.

Per the current SEC rules, the prices used to calculate our proved reserves and the present value of proved reserves set forth herein are made using the 12-month unweighted arithmetic average of the first-day-of-the-month price. All prices 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.

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, 2018	2017
Oil (Bbls):		
Proved developed – Producing	379,390	371,860
Proved developed – Non-producing	11,350	28,030
Proved undeveloped	805,980	1,724,420
Total	1,196,720	2,124,310
Natural gas (Mcf):		
Proved developed – Producing	3,774,490	3,817,490
Proved developed – Non-producing	328,900	290,460
Proved undeveloped	1,383,120	2,572,960
Total	5,486,510	6,680,910
Total net proved reserves (BOE)	2,111,140	3,237,795
PV-10 Value (1)	$22,001,900	$25,265,700
Present value of future income tax discounted at 10%	(3,125,900)	(6,182,700)
Standardized measure of discounted future net cash flows (2)	$18,876,000	$19,083,000
Prices used in Calculating Reserves: (3)		
Natural gas (per Mcf)	$3.031	$2.561
Oil (per Bbl)	$50.63	$43.88

(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 was computed by applying 12-month average prices for oil and gas during the fiscal year 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.

(3) These prices reflect adjustment by lease for quality, transportation fees and regional price differentials and did not give effect to derivative transactions.

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, 2018, and no major discovery is believed to have caused a significant change in our estimates of proved reserves since that date.

During the fiscal year ending March 31, 2018, we participated in the development of 16 wells converting reserves of approximately 70,500 BOE from proved undeveloped to proved developed – producing with capital cost of approximately $445,000.

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 Accounting Standard Codification (“ASC”) 932, “Extractive Activities - Oil and Gas”, 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.

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,			
	2018		2017	
	Gross	Net	Gross	Net
Development Wells				
Productive - Horizontal	23	.10	17	.11
Productive - Vertical	2	.01	4	.02
Nonproductive - Vertical	-	-	-	-
Total	25	.11	21	.13

We have not participated in any exploratory wells during the years ended March 31, 2018 and 2017. 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. The net numbers above represent Mexco's working interest in the gross wells.

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. As of March 31, 2018, we held an interest in approximately 6,000 gross (25 net) productive wells, including approximately 4,800 wells in which we held an overriding or royalty interest and 1,200 wells in which we held a working interest. Mexco operates 3 of its working interest producing wells.

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. The following table sets forth the approximate developed acreage in which we held a leasehold mineral or other interest as of March 31, 2018:

	Developed Acres	
	Gross	Net
Texas	345,700	1,727
Oklahoma	90,800	1,372
New Mexico	32,900	511
Louisiana	37,900	34
North Dakota	30,800	43
Kansas	9,700	24
Montana	7,800	5
Wyoming	3,800	5
Arkansas	1,000	5
Mississippi	1,600	3
Alabama	600	2
Colorado	1,100	.5
Virginia	100	.5
Total	563,800	3,734

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,	
	2018	2017
Oil (a):		
Production (Bbls)	34,743	34,689
Revenue	$1,789,736	$1,517,606
Average Bbls per day (d)	95	95
Average sales price per Bbl	$51.51	$43.75
Gas (b):		
Production (Mcf)	318,774	356,268
Revenue	$860,496	$819,616
Average Mcf per day (d)	873	976
Average sales price per Mcf	$2.70	$2.30
Production cost:		

Production cost	$870,806	$717,757
Production and ad valorem taxes	$199,641	$160,701
Total BOE (c)	87,872	94,067
Production cost per BOE	$9.91	$7.63
Production cost per sales dollar	$0.33	$0.31
Total oil and gas revenue	$2,650,232	$2,337,222

(a) Includes condensate.
(b) Includes natural gas products.
(c) Natural gas production is converted to oil production using a ratio of six Mcf to one Bbl of oil.
(d) Calculated on a 365 day year.

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. MINE SAFETY DISCLOSURES

Not applicable.

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 NYSE American, formerly the American Stock Exchange and more recently the NYSE MKT, 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 NYSE American.

		High	Low
2018:	April - June 2017	$4.95	$3.72
	July - September 2017	5.85	4.40
	October - December 2017	4.65	3.82
	January - March 2018	5.04	3.06
2017:	April - June 2016	$3.50	$2.24
	July - September 2016	4.37	2.65
	October - December 2016	5.07	3.81
	January - March 2017	5.39	3.52

On June 19, 2018, the closing sales price of our common stock on the NYSE American was $4.61 per share.

Stockholders

As of March 31, 2018, we had 2,104,266 shares issued and 872 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.

Securities Authorized for Issuance Under Compensation Plans

The following table includes certain information about our Employee Incentive Stock Plan as of March 31, 2018, 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
2009 Plan	200,000	148,600	$ 6.54	49,000
Total	200,000	148,600	$ 6.54	49,000

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Issuer Repurchases

In September 2017, the Board of Directors authorized the use of up to $250,000 to repurchase shares of our common stock for the treasury account. This program does not have an expiration date. Under the repurchase program, shares of common stock may be purchased from time to time through open market purchases or other transactions. The amount and timing of repurchases will be subject to the availability of stock, prevailing market conditions, the trading price of the stock, our financial performance and other conditions. Repurchases may also be made from time-to-time in connection with the settlement of our share-based compensation awards. Repurchases will be funded from cash flow from operations.

There were no shares of our common stock repurchased for the treasury account during the fiscal years ended March 31, 2018 and 2017.

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, sales of non-core properties and issuance of common stock. Our primary financial resource is our base of oil and gas reserves. We have pledged our producing oil and gas properties to secure our revolving line of credit. We do not have any delivery commitments to provide a fixed and determinable quantity of our oil and gas under any existing contract or agreement.

Due to the current commodity price environment, we are applying financial discipline to all aspects of our business. In order to meet obligations, we may continue to sell non-core assets.

Our long term strategy is on increasing profit margins while concentrating on obtaining reserves with low cost operations by acquiring and developing oil and gas properties with potential for long-lived production. We focus our efforts on the acquisition of minerals, royalties and working interests and non-operated properties in areas with significant development potential.

For the year ended March 31, 2018, cash flow from operations was $441,024, a 112% increase when compared to the corresponding period of fiscal 2017. Cash of $3,270,792 was received from the sale of oil and gas properties and drilling refunds, cash of $2,200,000 was used to reduce the line of credit, and cash of $1,092,657 was used for additions to oil and gas properties. Accordingly, net cash increased $419,159.

We had working capital of $925,618 as of March 31, 2018 compared to working capital of $367,675 as of March 31, 2017, an increase of $557,943 for the reasons set forth below.

Oil and Natural Gas Property Development

In addition to approximately 100 gross wells drilled by other operators on Mexco's royalty interests, the Company participated in the drilling and completion of 23 horizontal wells and 2 vertical wells located in the Permian Basin at a cost of approximately $816,000 for the fiscal year ending March 31, 2018. The operators of these wells include Concho Resources, Inc., Marathon Oil Permian LLC, McElvain Energy, Inc., Mewbourne Oil Company, XTO Energy, Inc. and others.

Seven of these wells are in the Yeso/Paddock formations of the Dodd Federal Unit in the Grayburg San Andres Jackson Field of Eddy County, New Mexico and operated by Concho Resources, Inc. The first three began producing in September at an initial average rate of 236 barrels of oil; 1,355 barrels of water; and 310,000 cubic feet of gas per day, or 288 barrels of oil equivalent per day. The fourth well began producing in November at an initial rate of 245 barrels of oil; 1,053 barrels of water; and 247,000 cubic feet of gas per day, or 286 barrels of oil equivalent per day. The last 3 wells are in various stages of drilling and completion. Mexco's working interest in this unit is .1848%.

Another three were completed in December 2017 and tested at an average rate of 1,162 barrels of oil; 2,283 barrels of water; and 1,991,000 cubic feet of gas per day, or 1,494 barrels of oil equivalent per day, with an average flowing tubing pressure of 647 pounds per square inch. These wells are in the Lower Avalon formation located in Lea County, New Mexico. Mexco's working interest in these wells is .6%.

In addition, four were completed in March 2018 and tested at an average rate of 839 barrels of oil; 2,140 barrels of water; and 1,288,000 cubic feet of gas per day, or 1,054 barrels of oil equivalent per day, with an average flowing tubing pressure of 865 pounds per square inch. These wells are in the Lower Avalon formation located in Lea County, New Mexico. Mexco's working interest in these wells range from .74% to .8%.

Also, two wells began producing in January 2018 at an initial average rate of 398 barrels of oil; 978 barrels of water; and 145,000 cubic feet of gas per day, or 422 barrels of oil equivalent per day. These two wells are in the Bone Spring formation located in Lea County, New Mexico. Mexco's working interest in the first well is 2.7% and .36% in the adjacent second well.

The remaining nine of the 25 wells have been drilled and either began producing in March 2018 or are in the final stages of completion.

Oil and Natural Gas Property Sales

During fiscal 2018, the Company continued its policy of selling non-core assets in order to concentrate on the development of more profitable assets and to pay down debt.

In April 2017, the Company sold for a total consideration of $460,461, leasehold interests in 137 net acres in the Scoop-Stack areas of Canadian and Grady Counties, Oklahoma. The first of these transactions in which the Company retained its interests in the existing producing wellbores on the acreage was in the amount of $336,730. The second transaction in the amount of $123,731 included the producing wellbores as well as the acreage. Of these proceeds, $410,000 was applied to reduce bank indebtedness and the balance of $50,461 was applied to working capital of the Company.

In June and November 2017, the Company received approximately $33,000 and $114,000, respectively, in cash from a sale of joint venture leasehold acreage in Reeves and Ward County, TX. The Company retained its interests in the existing producing wellbores in both counties.

In July 2017, the Company received approximately $49,000 in cash from a sale of joint venture leasehold acreage and marginal producing working interest wells in Ward County, TX.

In December 2017, the Company received approximately $1.9 million in cash from a sale of joint venture leasehold marginal producing working interests in several thousand acres located in Ward and Winkler Counties, Texas. Of these proceeds, approximately $1.518 million was applied to the Company's bank debt and the balance to the Company's working capital. Approximately $200,000 of the purchase price is being held in escrow pending payment of closing costs and resolution of title issues as to a small portion of the sale assets. This amount is reflected in accounts receivable trade on our consolidated balance sheets.

In December 2017, the Company received approximately $30,000 in cash from a sale of joint venture leasehold acreage and marginal producing working interest wells in Midland County, TX.

In January 2018, the Company sold additional leasehold interests in the Scoop-Stack area of Grady County, Oklahoma for $46,000 which the Company used to reduce bank indebtedness. The Company retained its interests in the existing producing wellbore on the acreage.

In January 2018, the Company received approximately $235,000 in cash from a sale of joint venture leasehold acreage and marginal producing working interest wells in Winkler County, TX.

Also in January 2018, the Company sold its working interests in two wells in Loving County, TX in which the Company was the operator. The Company received approximately $204,000 in cash before adjustments for its share of which $100,000 was applied to the Company's bank debt.

In March 2018, the Company sold its non-operated working interests in 6 producing oil wells and 1 salt water disposal well in Pecos County, TX for a cash price of $112,500 in which $100,000 was applied to the Company's bank debt.

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, cash flow from operations and sales of non-core properties.

Crude oil and natural gas prices generally increased during the last year. 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 $39.00 per bbl in June 2017 to a high of $62.75 per bbl in January 2018. The Henry Hub Spot Market Price ("Henry Hub") for natural gas has ranged from a low of $2.49 per MMBtu in February 2018 to a high of $6.24 per MMBtu in January 2018.

On March 31, 2018 the WTI posted price for crude oil was $61.50 per bbl and the Henry Hub spot price for natural gas was $2.81 per MMBtu. Management is of the opinion that cash flow from operations and sales of property and common stock of the Company will be sufficient to provide adequate liquidity for the next fiscal year.

Results of Operations

Fiscal 2018 Compared to Fiscal 2017

We had a net loss of $321,489 for the year ended March 31, 2018 compared to a net loss of $694,553 for the year ended March 31, 2017. We achieved net income of $264,461 for the fiscal quarter ended March 31, 2018.

Oil and gas sales. Revenue from oil and gas sales was $2,650,232 for the year ended March 31, 2018, a 13% increase from $2,337,222 for the year ended March 31, 2017. This resulted from an increase in oil and gas prices partially offset by a decrease in gas production. The following table sets forth our oil and gas revenues, production quantities and average prices received during the fiscal years ended March 31:

	2018	2017	% Difference	
Oil:				
Revenue	$1,789,736	$1,517,606	17.9	%
Volume (bbls)	34,743	34,689	0.2	%
Average Price (per bbl)	$51.51	$43.75	17.7	%
Gas:				
Revenue	$860,496	$819,616	5.0	%
Volume (mcf)	318,774	356,268	(10.5	%)
Average Price (per mcf)	$2.70	$2.30	17.4	%

Other operating revenue. Other operating revenue was $55,003 for fiscal 2018 compared to $188,141 for fiscal 2017 primarily due to the settlement of a lawsuit for underpayment of royalties from Chesapeake Energy Corporation and Total E & P USA in the amount of $148,614 during fiscal 2017 partially offset by an increase in SWD income.

Production and exploration. Production costs were $1,070,447 in fiscal 2018, a 22% increase from $878,458 in fiscal 2017. This was primarily the result of an increase in lease operating expenses and production taxes due to the increase in oil and gas revenues and XTO Energy, Inc. incorrectly providing us a refund for marketing and transportation fees of approximately $67,000 which is being reversed via monthly netting.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") expense was $880,419 in fiscal 2018, a 25% decrease from $1,177,422 in fiscal 2017. This was primarily due to a decrease in oil and gas production, a decrease in the full cost pool as a result of oil and gas property sales, and a decrease in oil and gas reserves.

General and administrative expenses. General and administrative expenses were $955,147 for the year ended March 31, 2018, a 2% decrease from $976,392 for the year ended March 31, 2017. This was primarily due to a decrease in engineering services, insurance expense and legal fees partially offset by an increase in accounting fees.

Interest expense. Interest expense was $89,537 in fiscal 2018, a 41% decrease from $152,126 in fiscal 2017, due to a decrease in borrowings partially offset by an increase in interest rate.

Income taxes. There was no income tax for fiscal 2018 or fiscal 2017. The effective tax rate for fiscal 2018 and fiscal 2017 was 0%. We are in a net deferred tax asset position and believe it is more likely than not that these deferred tax assets will not be realized.

Fiscal 2017 Compared to Fiscal 2016

We had a net loss of $694,553 for the year ended March 31, 2017 compared to a net loss of $3,979,685 for the year ended March 31, 2016.

Oil and gas sales. Revenue from oil and gas sales was $2,337,222 for the year ended March 31, 2017, a 2% decrease from $2,383,950 for the year ended March 31, 2016. This resulted from a decrease in oil and gas production 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 during the fiscal years ended March 31:

	2017	2016	% Difference	
Oil:				
Revenue	$1,517,606	$1,598,725	(5.1	%)
Volume (bbls)	34,689	38,930	(10.9	%)
Average Price (per bbl)	$43.75	$41.07	6.5	%
Gas:				

Revenue	$819,616	$785,225	4.4	%
Volume (mcf)	356,268	407,939	(12.7	%)
Average Price (per mcf)	$2.30	$1.92	19.8	%

Other operating revenue. Other operating revenue was $188,141 for fiscal 2017 compared to $37,842 for fiscal 2016 primarily due to the settlement of a lawsuit for underpayment of royalties from Chesapeake Energy Corporation and Total E & P USA in the amount of $148,614.

Production and exploration. Production costs were $878,458 in fiscal 2017, a 23% decrease from $1,144,061 in fiscal 2016. This was primarily the result of a decrease in lease operating expenses as a result of lowering service costs and the sale of our operated properties in Pecos County, Texas.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") expense was $1,177,422 in fiscal 2017, a 25% decrease from $1,572,738 in fiscal 2016. This was due to a decrease in oil and gas production, a decrease in the full cost pool amortization base and an increase in oil and gas reserves.

General and administrative expenses. General and administrative expenses were $976,392 for the year ended March 31, 2017, a 15% decrease from $1,155,183 for the year ended March 31, 2016. This was primarily due to a decrease in engineering services, insurance expense, salaries and stock option compensation.

Interest expense. Interest expense was $152,126 in fiscal 2017, an 11% decrease from $171,375 in fiscal 2016, due to a decrease in borrowings partially offset by an increase in interest rate.

Income taxes. There was no income tax for fiscal 2017 compared to an income tax benefit of $660,870 in fiscal 2016. The effective tax rate for fiscal 2017 was 0% compared to (14%) for fiscal 2016. This change in the effective income tax rate is primarily due to the tax benefit at expected rates being offset by an increase in our valuation allowance. We are in a net deferred tax asset position at year end and believe it is more likely than not that these deferred tax assets will not be realized.

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 future payments we are obligated to make based on agreements in place as of March 31, 2018:

	Payments due in:			
	Total	less than 1 year	1 - 3 years	over 3 years
Contractual obligations:				
Secured bank line of credit (1)	$700,000	$ -	$700,000	$ -
Leases (2)	$-	$ -	$-	$ -

(1) These amounts represent the balances outstanding under the bank line of credit. These repayments assume that interest will be paid on a monthly basis, no additional funds will be drawn and does not include estimated interest of $34,125 less than 1 year and $56,875 1-3 years.

(2) The lease amount represents the monthly rent amount for our principal office space in Midland, Texas under one three year lease agreement effective April 1, 2013. In February 2016, the option to renew the lease for two years was exercised. The lease expired on April 1, 2018.

Alternative Capital Resources

Although we have primarily used cash from operating activities and sales of assets 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 issuances of our common stock through a private placement or public offering.

Other Matters

Critical Accounting Policies and Estimates

In preparing financial statements, management makes 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. 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 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 impairment to our oil and gas properties 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 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 are 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 plugging, 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.

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 exceed 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).

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.

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.

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.

Recent Accounting Pronouncements. In February 2016, the Financial Accounting Standards Board ("FASB") issued ASU 2016-02, Topic 842 Leases, which requires companies to include leases with a term greater than one year on their balance sheets, but recognize lease costs on the income statement in a manner similar to accounting for leases prior to ASU 2016-02. The standard is effective for fiscal years beginning after December 15, 2018, and interim periods thereafter. Early adoption is permitted. The Company is still determining the impact of this amendment.

In May 2014, the FASB issued ASU updated No. 2014-09, Topic 606: Revenue from Contracts with Customers. Under the amendments in this update, recognition of revenue occurs when a customer obtains control of promised goods or services in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the new standard requires that reporting companies disclose the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments in this update are effective for fiscal years and interim periods within those years beginning after December 15, 2017. The new standard is required to be applied either retrospectively to each prior reporting period presented, or retrospectively with the cumulative effect of applying the update recognized at the date of initial application. The Company has determined that implementation of this amendment will not result in any change to its financial statements other than mandatory disclosure items.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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.

Interest Rate Risk. On March 31, 2018, we had an outstanding loan balance of $700,000 under our 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 3.0 percentage points. If the interest rate on our bank debt increases or decreases by one percentage point our annual pretax income would change by $7,000 based on borrowings at March 31, 2018.

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, 2018, our largest credit risk associated with any single purchaser was $123,447 or 32% of our total oil and gas receivables. 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 credit facility and adversely affect the amount of cash flow available for capital expenditures and our ability to obtain additional capital for our acquisition, 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. If the average oil price had increased or decreased by five dollars per barrel for fiscal 2018, our oil and gas revenue would have changed by $173,715. If the average gas price had increased or decreased by one dollar per mcf for fiscal 2018, oil and gas revenue would have changed by $318,774.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears on pages F1 through F20 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. The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f) and 15d-15(f). The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements. Our internal control over financial reporting is supported by appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel, and a written Code of Conduct adopted by our Board of Directors, applicable to all directors, officers and employees of Mexco.

Our chief executive officer and chief financial officer assessed the effectiveness our internal control over financial reporting using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the 2013 "Internal Control - Integrated Framework". Based upon that evaluation, our chief executive officer and chief financial officer concluded that our internal control over financial reporting was effective as of March 31, 2018.

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 Rule 13a-15(e). Based on such evaluation, such officers concluded that, as of March 31, 2018, our disclosure controls and procedures were effective.

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, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 11, 2018 (“Proxy Statement”) to be filed with the SEC within 120 days after the end of our fiscal year ended March 31, 2018, 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 F21 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*	By:*/s/ Tamala L. McComic*
Chairman of the Board and Chief Executive Officer	President and Chief Financial Officer

Dated: June 26, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below as of June 26, 2018, by the following persons on behalf of the Registrant and in the capacity indicated.

/s/ Nicholas C. Taylor
Nicholas C. Taylor
Chief Executive Officer, Chairman of the Board of Directors

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

/s/ Michael J. Banschbach
Michael J. Banschbach
Director

/s/ Kenneth L. Clayton
Kenneth L. Clayton
Director

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

/s/ Paul G. Hines
Paul G. Hines

Director

/s/ Christopher M. Schroeder
Christopher M. Schroeder
Director

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Glossary of Abbreviations and Terms

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

Basin. A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

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.

BOE. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

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 bank or group of banks, secured by oil and gas properties.

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

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

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

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

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

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

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

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

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

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.

MBOE. One thousand barrels of oil equivalent.

MMBOE. One million barrels of oil equivalent.

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.

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.

Shut in. A well suspended from production or injection but not abandoned.

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Mexco Energy Corporation (the "Company") as of March 31, 2018, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for the year then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of March 31, 2018, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting 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.

Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ WEAVER AND TIDWELL, L.L.P.

We have served as the Company's auditor since 2017.

Midland, Texas

June 26, 2018

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Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders

Mexco Energy Corporation

We have audited the accompanying consolidated balance sheet of Mexco Energy Corporation (a Colorado corporation) and Subsidiaries (the "Company") as of March 31, 2017 and the related consolidated statements of operations, changes in stockholders' equity and cash flows for year then ended. 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 audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit 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 audit provides 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, 2017, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

June 27, 2017

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Mexco Energy Corporation and Subsidiaries

CONSOLIDATED BALANCE SHEETS

	March 31, 2018	March 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$492,610	$73,451
Accounts receivable:		
Oil and gas sales	395,991	381,414
Trade	436,249	13,744
Prepaid costs and expenses	47,583	36,325
Total current assets	1,372,433	504,934
Property and equipment, at cost		
Oil and gas properties, using the full cost method	35,224,784	37,640,096
Other	107,484	107,484
Accumulated depreciation, depletion and amortization	(26,453,025)	(25,572,606)
Property and equipment, net	8,879,243	12,174,974
Other noncurrent assets	149,278	28,157
Total assets	$10,400,954	$12,708,065
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$446,815	$137,259
Total current liabilities	446,815	137,259
Long-term debt	700,000	2,900,000
Asset retirement obligations	852,553	968,484
Total liabilities	1,999,368	4,005,743
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; 2,104,266 shares issued and 2,037,266 shares outstanding as of March 31, 2018 and 2017, respectively	1,052,133	1,052,133
Additional paid-in capital	7,265,601	7,244,848
Retained earnings	429,853	751,342
Treasury stock, at cost (67,000 shares)	(346,001)	(346,001)
Total stockholders' equity	8,401,586	8,702,322
Total liabilities and stockholders' equity	$10,400,954	$12,708,065

The accompanying notes to the consolidated financial statements

are an integral part of these statements.

Mexco Energy Corporation and Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS

Years ended March 31,

	2018	2017
Operating revenues:		
Oil and gas	$2,650,232	$2,337,222
Other	55,003	188,141
Total operating revenues	2,705,235	2,525,363
Operating expenses:		
Production	1,070,447	878,458
Accretion of asset retirement obligation	31,460	35,743
Depreciation, depletion and amortization	880,419	1,177,422
General and administrative	955,147	976,392
Total operating expenses	2,937,473	3,068,015
Operating loss	(232,238)	(542,652)
Other income (expenses):		
Interest income	286	225
Interest expense	(89,537)	(152,126)
Net other (expense) income	(89,251)	(151,901)
Loss before provision for income taxes	(321,489)	(694,553)
Income tax	-	-
Net loss	$(321,489)	$(694,553)
Loss per common share:		
Basic:	$(0.16)	$(0.34)
Diluted:	$(0.16)	$(0.34)
Weighted average common shares outstanding:		
Basic:	2,037,266	2,037,266
Diluted:	2,037,266	2,037,266

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

Years ended March 31, 2018 and 2017

	Common Stock Par Value	Treasury Stock	Additional Paid-In Capital	Retained Earnings	Total Stockholders' Equity
Balance at April 1, 2016	$1,052,133	$(346,001)	$7,191,984	$1,445,895	$9,344,011
Net loss	-	-	-	(694,553)	(694,553)
Stock based compensation	-	-	52,864	-	52,864
Balance at March 31, 2017	$1,052,133	$(346,001)	$7,244,848	$751,342	$8,702,322
Net loss	-	-	-	(321,489)	(321,489)
Stock based compensation	-	-	20,753	-	20,753
Balance at March 31, 2018	$1,052,133	$(346,001)	$7,265,601	$429,483	$8,401,586

SHARE ACTIVITY

	2018	2017
Common stock shares, issued:		
At beginning of year	2,104,266	2,104,266
Issued	-	-
At end of year	2,104,266	2,104,266
Common stock shares, held in treasury:		
At beginning of year	(67,000)	(67,000)
Acquisitions	-	-
At end of year	(67,000)	(67,000)
Common stock shares, outstanding		
At end of year	2,037,266	2,037,266

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

Years ended March 31,

	2018	2017
Cash flows from operating activities:		
Net loss	$(321,489)	$(694,553)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Stock-based compensation	20,753	52,864
Depreciation, depletion and amortization	880,419	1,177,422
Accretion of asset retirement obligations	31,460	35,743
Changes in operating assets and liabilities:		
Increase in accounts receivable	(437,083)	(117,133)
(Increase) decrease in prepaid expenses	(11,258)	6,959
Increase in noncurrent assets	-	(25,219)
Increase (decrease) in accounts payable and accrued expenses	303,831	(124,002)
Settlement of asset retirement obligations	(25,609)	(104,369)
Net cash provided by operating activities	441,024	207,712
Cash flows from investing activities:		
Additions to oil and gas properties	(1,092,657)	(802,311)
Drilling refunds	108,646	82,922
Proceeds from sale of oil and gas properties and equipment	3,162,146	3,231,115
Net cash provided by investing activities	2,178,135	2,511,726
Cash flows from financing activities:		
Reduction of long-term debt	(2,200,000)	(2,680,000)
Net cash used in financing activities	(2,200,000)	(2,680,000)
Net increase in cash and cash equivalents	419,159	39,438
Cash and cash equivalents at beginning of period	73,451	34,013
Cash and cash equivalents at end of period	$492,610	$73,451
Supplemental disclosure of cash flow information:		
Cash paid for interest	$94,880	$156,142
Non-cash investing and financing activities:		
Asset retirement obligations	$6,689	$8,753

The accompanying notes to the consolidated financial statements

are an integral part of these statements.

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MEXCO ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended March 31, 2018 and 2017

1. Nature of Operations

Mexco Energy Corporation (a Colorado corporation) and its wholly owned subsidiaries, Forman Energy Corporation (a New York corporation), Southwest Texas Disposal Corporation (a Texas corporation) and TBO Oil & Gas, LLC (a Texas limited liability company) (collectively, the “Company”) are engaged in the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids (“NGLs”). Most of the Company’s oil and gas interests are centered in West Texas; however, the Company owns producing properties and undeveloped acreage in thirteen states. Although the Company’s oil and gas interests predominately are operated by others, the Company operates three wells in which it owns an interest.

2. Summary of Significant Accounting Policies

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

Estimates and Assumptions. In preparing financial statements in conformity with accounting principles generally accepted in the United States of America (“GAAP”), 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 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 the Company’s 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. The Company considers all highly liquid debt instruments purchased with maturities of three months or less and money market funds to be cash equivalents. The Company maintains cash in bank deposit accounts that may, at times, exceed federally insured limits. At March 31, 2018, the Company had all of its cash and cash equivalents with one financial institution. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk.

Accounts Receivable. Accounts receivable includes 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 collectibility of receivables is assessed and an allowance is made for any doubtful accounts. The allowance for doubtful accounts is determined based on the Company's previous loss history. The Company has not experienced any significant credit losses. For the years ended March 31, 2018 and 2017, 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.

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 the after tax present value of the future net cash flows from proved crude oil and natural gas reserves and using an average price over the prior first day of the month 12-month period held flat for the life of production 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, the Company 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 impairment to our oil and gas properties does not impact cash flow from operating activities, but does reduce 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. The Company has significant obligations to plug and abandon natural gas and crude oil wells and related equipment at the end of oil and gas production operations. The Company records 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 Statements 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. The Company uses 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.

Loss Per Common Share. Basic net loss per share is computed by dividing net loss by the weighted average number of common shares outstanding during the period. Diluted net loss 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 loss 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.

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. The Company has 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 excess takes of natural gas volumes exceed estimated remaining recoverable reserves (over produced). No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production (under produced). The Company does not have any significant gas imbalances.

Stock-based Compensation. The Company uses 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 its consolidated financial statements over the vesting period. The Company recognizes the fair value of stock-based compensation awards as wages within general and administrative expense in the Consolidated Statements of Operations based on a graded-vesting schedule over the vesting period.

Reclassifications. Certain amounts in prior periods' consolidated financial statements have been reclassified to conform with the current period's presentation. These reclassifications had no effect on previously reported results of operations, retained earnings or net cash flows.

Recent Accounting Pronouncements. In February 2016, the FASB issued ASU 2016-02, Topic 842 Leases, which requires companies to include leases with a term greater than one year on their balance sheets, but recognize lease costs on the income statement in a manner similar to accounting for leases prior to ASU 2016-02. The standard is effective for fiscal years beginning after December 15, 2018, and interim periods thereafter. Early adoption is permitted. The Company is still determining the impact of this amendment.

In May 2014, the FASB issued ASU updated No. 2014-09, Topic 606: Revenue from Contracts with Customers. Under the amendments in this update, recognition of revenue occurs when a customer obtains control of promised goods or services in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the new standard requires that reporting companies disclose the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments in this update are effective for fiscal years and interim periods within those years beginning after December 15, 2017. The new standard is required to be applied either retrospectively to each prior reporting period presented, or retrospectively with the cumulative effect of applying the update recognized at the date of initial application. The Company has determined that implementation of this amendment will not result in any change to its consolidated financial statements other than mandatory disclosure items.

Liquidity and Capital Resources. Historically, we have funded our operations, acquisitions, exploration and development expenditures from cash generated by operating activities, bank borrowings, sales of non-core properties and issuance of common stock. Our long term strategy is on increasing profit margins while concentrating on obtaining reserves with low cost operations by acquiring and developing oil and gas properties with potential for long-lived production. We focus our efforts on the acquisition of royalties and working interest, non-operated properties in areas with significant development potential.

3. Fair Value of Financial Instruments

The carrying amount reported in the accompanying consolidated balance sheets for cash and cash equivalents, accounts receivable and accounts payable approximates fair value because of the immediate or short-term maturity of these financial instruments.

The fair value 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. See the Company's Note 5 on Credit Facility for further discussion.

4. Property Sales

During fiscal 2018, the Company continued its policy of selling non-core assets in order to concentrate on the development of more profitable assets and to pay down debt.

In April 2017, the Company sold for a total consideration of $460,461, leasehold interests in 137 net acres in the Scoop-Stack areas of Canadian and Grady Counties, Oklahoma. The first of these transactions in which the Company retained its interests in the existing producing wellbores on the acreage was in the amount of $336,730. The second transaction in the amount of $123,731 included the producing wellbores as well as the acreage. Of these proceeds, $410,000 was applied to reduce bank indebtedness and the balance of $50,461 was applied to working capital of the Company.

In June and November 2017, the Company received approximately $33,000 and $114,000, respectively, in cash from a sale of joint venture leasehold acreage in Reeves and Ward County, TX. The Company retained its interests in the existing producing wellbores in both counties.

In July 2017, the Company received approximately $49,000 in cash from a sale of joint venture leasehold acreage and marginal producing working interest wells in Ward County, TX.

In December 2017, the Company received approximately $30,000 in cash from a sale of joint venture leasehold acreage and marginal producing working interest wells in Midland County, TX.

In December 2017, the Company received approximately $1.9 million in cash from a sale of joint venture leasehold marginal producing working interests in several thousand acres located in Ward and Winkler Counties, Texas. Of these proceeds, approximately $1.518 million was applied to the Company’s bank debt and the balance to the Company’s working capital. Approximately $200,000 of the purchase price is being held in escrow pending payment of closing costs and resolution of title issues as to a small portion of the sale assets. This amount is reflected in accounts receivable trade on our consolidated balance sheets.

In January 2018, the Company sold additional leasehold interests in the Scoop-Stack area of Grady County, Oklahoma for $46,000 which the Company used to reduce bank indebtedness. The Company retained its interests in the existing producing wellbore on the acreage.

In January 2018, the Company received approximately $235,000 in cash from a sale of joint venture leasehold acreage and marginal producing working interest wells in Winkler County, TX.

Also in January 2018, the Company sold its working interests in two wells in Loving County, TX in which the Company was the operator. The Company received approximately $204,000 in cash for its share of which $100,000 was applied to the Company’s bank debt.

In March 2018, the Company sold its non-operated working interests in 6 producing oil wells and 1 salt water disposal well in Pecos County, TX for a cash purchase price of $112,500 in which $100,000 was applied to the Company’s bank debt.

5. Credit Facility

The Company has a loan agreement with Bank of America, N.A. (the “Agreement”), which provided for a credit facility of $5,570,000 with no monthly commitment reductions and a borrowing base to be evaluated on July 30 and January 1 of each year or at any additional time in the bank's discretion. The borrowing base was evaluated on January 26, 2018 and set at $950,000. The borrowing base also resets to the extent the Company sells or otherwise disposes of any of its oil and gas properties as the Company is required to pay 100% of such net proceeds to the lender resulting in a permanent reduction of the borrowing base unless prior approval by the bank states otherwise. As of March 31, 2018, the borrowing base was set at $700,000.

The Agreement was renewed eleven times with the eleventh amendment effective as of March 8, 2017 with a maturity date of November 30, 2020. Under such renewal agreement, 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 3.0 percentage points, which was 4.875% on March 31, 2018. Interest on the outstanding amount under the credit agreement is payable monthly. There was no availability of this line of credit at March 31, 2018. No principal payments are anticipated to be required through November 30, 2020. Amounts borrowed under the Agreement are collateralized by the common stock of the Company's wholly owned subsidiaries and substantially all of the Company's oil and gas properties.

The Agreement contains customary covenants for credit facilities of this type including limitations on change in control, disposition of assets, mergers and reorganizations. The Company is also obligated to meet certain financial covenants under the Agreement and requires minimum earnings before interest, taxes, depreciation and amortization ("EBITDA") of $650,000 for each trailing four fiscal quarters and minimum interest coverage ratios (EBITDA/Interest Expense) of 2.00 to 1.00 for each quarter. The Company is in compliance with all covenants as of March 31, 2018 and believes it will remain in compliance for the next fiscal year.

In addition, this Agreement prohibits the Company from paying cash dividends on its common stock. The Agreement does grant the Company permission to enter into hedge agreements however, it is under no obligation to do so.

The amended Agreement allows for up to $500,000 of the facility to be used for outstanding letters of credits. As of March 31, 2018, one letter of credit for $50,000 is outstanding under the facility. This letter of credit is in lieu of a plugging bond with the Texas Railroad Commission ("TRRC") covering the properties the Company operates and renews annually. The Company will pay a fee in an amount equal to 1 percent (1.0%) per annum of the outstanding undrawn amount of each standby letter of credit, payable monthly in arrears, on the basis of the face amount outstanding on the day the fee is calculated.

The balance outstanding on the line of credit as of March 31, 2018 was $700,000 and as of June 15, 2018 was $500,000. The following table is a summary of activity on the Bank of America, N.A. line of credit for the year ended March 31, 2018:

	Principal
Balance at April 1, 2017:	$2,900,000
Borrowings	-
Repayments	(2,200,000)
Balance at March 31, 2018:	$700,000

6. Asset Retirement Obligations

The Company'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 until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our oil and natural gas properties. The ARO is included on the consolidated balance sheets with the current portion being included in the accounts payable and accrued expenses.

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

	2018	2017
Carrying amount of asset retirement obligations, beginning of year	$978,484	$1,221,077
Liabilities incurred	6,689	8,753
Liabilities settled	(153,539)	(287,089)
Accretion expense	31,460	35,743
Revisions	(541)	-
Carrying amount of asset retirement obligations, end of year	862,553	978,484

Less: Current portion	10,000	10,000
Non-Current asset retirement obligation	$852,553	$968,484

7. Income Taxes

The Company files a consolidated federal income tax return and various state income tax returns. The amount of income taxes the Company records requires the interpretation of complex rules and regulations of federal and state taxing jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal and state income tax examinations by tax authorities for years prior to 2015.

On December 22, 2017, the tax legislation referred to as the "Tax Cuts and Jobs Act" (the 2017 Tax Reform Act) was enacted. The more significant changes that impact the Company are the reduction in the corporate federal income tax rate from 35% to 21%. GAAP requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. The Company's deferred income taxes were remeasured based upon the new tax rates which amounted to a $466,020 reduction in deferred tax asset and valuation amount.

The 2017 Tax Reform Act reduced the corporate federal statutory income tax rate from 35% to 21% generally effective for tax years beginning on or after January 1, 2018. However, companies with fiscal years that include January 1, 2018 must use a blended rate. Our corporate federal statutory income tax rate will be 21% starting in fiscal 2019.

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

	2018	2017
Deferred tax assets:		
Percentage depletion carryforwards	$1,111,801	$1,786,522
Deferred stock-based compensation	33,581	52,654
Asset retirement obligation	181,136	332,685
Net operating loss	995,489	1,012,138
Other	5,141	7,170
	2,327,148	3,191,169
Deferred tax liabilities:		
Excess financial accounting bases over tax bases of property and equipment	1,091,725	2,052,749
Deferred tax asset, net	$1,235,423	$1,138,420
Valuation allowance	(1,235,423)	(1,138,420)
Net deferred tax	$-	$-

As of March 31, 2018, the Company has a statutory depletion carryforward of approximately $5,300,000, which does not expire. At March 31, 2018, the Company had a net operating loss carryforward for regular income tax reporting purposes of approximately $4,700,000, which will begin expiring in 2029. The Company's ability to use some of its net operating loss carryforwards and certain other tax attributes to reduce current and future U.S. federal taxable income is subject to limitations under the Internal Revenue Code.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry.

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

	2018	2017
Tax expense at federal statutory rate (1)	$(98,858)	$(236,148)
Statutory depletion carryforward	(8,361)	(67,801)
Change in valuation allowance	(362,908)	289,456
U. S. tax reform, corporate rate reduction	466,020	-
Permanent differences	3,506	14,497
Other	601	(4)

Total income tax	$-	$-
Effective income tax rate	-	-

(1) The federal statutory rate was 30.75% for fiscal year ending March 31, 2018 and 34% for fiscal year ending March 31, 2017.

For the years ended March 31, 2018 and 2017, the Company did not have any uncertain tax positions.

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

	2018	2017
Unrecognized tax benefits at beginning of period	$745,000	$679,000
Change based on tax positions related to the current year	(745,000)	66,000
Changes to tax positions of prior years	-	-
Settlements	-	-
Expirations	-	-
Unrecognized tax benefits at end of period	$-	$745,000

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While the amount of unrecognized tax benefits may change in the next 12 months, the Company does not expect any change to have a significant impact on its results of operations. The recognition of the total amount of the unrecognized tax benefits would have an impact on the effective tax rate. If these unrecognized tax benefits are disallowed, the Company will be required to pay additional taxes.

Based on the material write-downs of the carrying value of our oil and natural gas properties for the year ending March 31, 2016, we are in a net deferred tax asset position for years ending March 31, 2018 and 2017. Our deferred tax asset is $1,235,423 as of March 31, 2018 with a valuation amount of $1,235,423. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

8. Major Customers

Currently, the Company operates exclusively within the United States and its revenues and operating profit are derived from the oil and gas industry. Oil and gas production is sold to various purchasers and the receivables are unsecured. Historically, the Company has not experienced significant credit losses on its 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 the Company’s ability to sell its oil and gas production.

In fiscal 2018, one customer accounted for 37% of the total oil and gas revenues and 33% of the total oil and gas accounts receivable and another customer accounted for 8% of the total oil and gas revenues and 7% of the total oil and gas accounts receivable. In fiscal 2017, one customer accounted for 31% of the total oil and gas revenues and 32% of the total oil and gas accounts receivable and another customer accounted for 12% of the total oil and gas revenues and 5% of the total oil and gas accounts receivable.

9. Oil and Gas Costs

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

	2018	2017
Property acquisition costs:		

Proved	$-	$-
Unproved	-	-
Exploration	-	-
Development	1,099,051	731,400
Capitalized asset retirement obligations	6,689	8,753
Total costs incurred for oil and gas properties	$1,105,740	$740,153

The Company had the following aggregate capitalized costs relating to its oil and gas property activities at March 31:

	2018	2017
Proved oil and gas properties	$35,224,784	$37,640,096
Unproved oil and gas properties:		
subject to amortization	-	-
not subject to amortization	-	-
	35,224,784	37,640,096
Less accumulated DD&A	26,355,604	25,479,335
	$8,896,180	$12,160,761

DD&A amounted to $10.02 and $12.47 per BOE of production for the years ended March 31, 2018 and 2017, respectively.

10. Loss Per Common Share

Due to a net loss for the years ended March 31, 2018 and 2017, the weighted average number of common shares outstanding excludes common stock equivalents 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 years ended March 31:

	2018	2017
Net loss	$(321,489)	$(694,553)
Shares outstanding:		
Weighted avg. common shares outstanding – basic	2,037,266	2,037,266
Effect of the assumed exercise of dilutive stock options	-	-
Weighted avg. common shares outstanding – dilutive	2,037,266	2,037,266
Loss per common share:		
Basic	$(0.16)	$(0.34)
Diluted	$(0.16)	$(0.34)

11. Stockholders' Equity

In September 2017, the Board of Directors authorized the use of up to $250,000 to repurchase shares of the Company's common stock for the treasury account. There were no shares of common stock repurchased for the treasury account during fiscal 2018 and 2017.

12. Stock Options

In September 2009, the Company adopted the 2009 Employee Incentive Stock Plan (the "2009 Plan"). 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. 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. The 2009 Plan expires ten years from the date of adoption.

According to the Company's employee stock incentive plan, new shares will be issued upon the exercise of stock options and the Company can repurchase shares exercised under the plan. The plan also provides for the granting of stock awards. No stock awards were granted during fiscal 2018 and 2017.

The Company recognized compensation expense of $20,753 and $52,864 related to vesting stock options in general and administrative expense in the Consolidated Statements of Operations for fiscal 2018 and 2017, respectively. The total cost related to non-vested awards not yet recognized at March 31, 2018 totals $4,667, which is expected to be recognized over a weighted average of .42 years.

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 contractual term of 120 months and other factors. The Company uses 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 years ended March 31, 2018 and 2017, no stock options were granted.

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, 2018, vested stock options covering 1,000 shares were forfeited due to the resignation of an employee. During the year ended March 31, 2017, 3,000 vested stock options expired because there were not exercised and 1,000 unvested stock options were forfeited due to the resignation of an employee.

The following table is a summary of activity of stock options for the years ended March 31, 2018 and 2017:

	Number of Shares	Weighted Average Exercise Price Per Share	Weighted Aggregate Average Remaining Contract Life in Years
Outstanding at April 1, 2016	153,600	$ 6.52	6.36
Granted	-	-	
Exercised	-	-	
Forfeited or Expired	(4,000)	5.98	
Outstanding at March 31, 2017	149,600	$ 6.54	5.34
Granted	-	-	
Exercised	-	-	
Forfeited or Expired	(1,000)	5.98	
Outstanding at March 31, 2018	148,600	$ 6.54	4.34
Vested at March 31, 2018	138,600	$ 6.51	4.19
Exercisable at March 31, 2018	138,600	$ 6.51	4.19

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

	2018	2017
Weighted average grant-date fair value of stock options granted (per share)	$-	$-
Total fair value of options vested	$91,525	$92,713
Total intrinsic value of options exercised	$-	$-

The following table summarizes information about options outstanding at March 31, 2018:

Range of Exercise Prices	Number of Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contract Life in Years
$5.98 – 6.25	40,000	$ 6.00	
6.26 – 6.50	28,600	6.29	
6.51 – 6.80	40,000	6.80	
6.81 – 7.00	40,000	7.00	
$5.98 – 7.00	148,600	$ 6.54	4.34

Outstanding options at March 31, 2018 expire between August 2020 and August 2024 and have exercise prices ranging from $5.98 to $7.00.

13. Related Party Transactions

Related party transactions for the Company relate to shared office expenditures in addition to administrative and operating expenses paid on behalf of the principal stockholder. The total billed to and reimbursed by the stockholder for the years ended March 31, 2018 and 2017 were $40,432 and $35,263, respectively.

14. Lease Commitments

The Company leases its principal office space. On April 1, 2013, the Company agreed to a three year lease, with an option to renew for an additional two years. In February 2016, the option to renew the lease for two years was exercised. The lease expired on April 1, 2018. There is no further commitment under this lease.

Lease expense was $23,440 for each of the fiscal years ended March 31, 2018 and 2017.

15. Oil and Gas Reserve Data (Unaudited)

The estimates of the Company's proved oil and gas reserves, which are located entirely within the United States, were prepared in accordance with the generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The estimates as of March 31, 2018 were based on evaluations prepared by Russell K. Hall and Associates, Inc. The estimates as of March 31, 2017 were based on evaluations prepared by Joe C. Neal and Associates, Petroleum and Environmental Engineering Consultants. The services provided by Russell K. Hall and Associates, Inc. are not audits of our reserves but instead consist of complete engineering evaluations of the respective properties. For more information about their evaluations performed, refer to the copy of their report filed as an exhibit to this Annual Report on Form 10-K. Management emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table summarizes the prices utilized in the reserve estimates for 2018 and 2017. Commodity prices utilized for the reserve estimates prior to adjustments for location, grade and quality are as follows:

	March 31,	
	2018	2017
Prices utilized in the reserve estimates before adjustments:		
Oil per Bbl	$49.94	$44.10
Natural gas per MMBtu	$3.00	$2.74

The Company's total estimated proved reserves at March 31, 2018 were approximately 2.111 MBOE of which 57% was oil and natural gas liquids and 43% was natural gas.

Changes in Proved Reserves:

	Oil (Bbls)	Natural Gas (Mcf)
Proved Developed and Undeveloped Reserves:		
As of April 1, 2016	1,084,000	5,801,000
Revision of previous estimates	205,000	946,000
Purchase of minerals in place	-	-
Extensions and discoveries	962,000	1,380,000
Sales of minerals in place	(92,000)	(1,090,000)
Production	(35,000)	(356,000)
As of March 31, 2017	2,124,000	6,681,000
Revision of previous estimates	(850,000)	(915,000)
Purchase of minerals in place	-	-
Extensions and discoveries	110,000	191,000
Sales of minerals in place	(152,000)	(151,000)
Production	(35,000)	(319,000)
As of March 31, 2018	1,197,000	5,487,000

Proved developed reserves are those expected to be recovered through existing wells, equipment and operating methods. Proved undeveloped reserves (“PUD”) are 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 within a five years of the date of their initial recognition. Moreover, the Company may be required to write down its proved undeveloped reserves if the operators do not drill on the reserves within the required five-year timeframe. The downward revision of oil and natural gas is primarily the result of restructuring the plans for development of a non-producing leasehold interest in Martin County, Texas located in the Eastern Permian Basin partially offset by pricing and successful development in the Delaware and Midland Basins. Reserves written off due to the five year limitation are primarily in the Newark East field in Denton County, Texas which are on a lease held by production and are still in place to be developed in the future.

Summary of Proved Developed and Undeveloped Reserves as of March 31, 2018 and 2017:

	Oil (Bbls)	Natural Gas (Mcf)
Proved Developed Reserves:		
As of April 1, 2016	350,180	4,406,060
As of March 31, 2017	399,880	4,107,950
As of March 31, 2018	390,740	4,103,390
Proved Undeveloped Reserves:		
As of April 1, 2016	734,170	1,395,220
As of March 31, 2017	1,724,420	2,572,960
As of March 31, 2018	805,980	1,383,120

At March 31, 2018, the Company reported estimated PUDs of 1,037 MBOE, which accounted for 49% of its total estimated proved oil and gas reserves. This figure primarily consists of a projected 102 new wells (937 MBOE), 4 of which the Company operates with reserves of 205 MBOE, which will be drilled on existing acreage in the Goldsmith field where the Company currently operates 3 wells. The Company projects these 4 operated wells will be drilled in fiscal 2019.

Regarding the remaining 98 PUD locations operated by others (732 MBOE), 7 wells are currently being drilled with plans for 38 wells to follow in 2019, 33 wells in 2020 and 24 wells in 2021. The cost of these projects would be funded, to the extent possible, from existing cash balances and cash flow from operations. The remainder may be funded through non-core asset sales and/or sales of our common stock.

The following table discloses the Company's progress toward the conversion of PUDs during fiscal 2018.

Progress of Converting Proved Undeveloped Reserves:

	Oil & Natural Gas (BOE)	Future Development Costs
PUDs, beginning of year	2,153,248	$28,809,230
Revision of previous estimates	(998,890)	(16,475,396)

Sales of reserves	(159,759)	(2,043,502)
Conversions to PD reserves	(70,453)	(445,406)
Additional PUDs added	112,357	2,164,405
PUDs, end of year	1,036,503	$12,009,331

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using average prices for 2018 and 2017 along with estimates of the operating costs, production taxes and future development costs necessary to produce such reserves. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

Operating costs and production taxes are estimated based on current costs with respect to producing oil and natural gas properties. Future development costs including abandonment costs are based on the best estimate of such costs assuming current economic and operating conditions. The future cash flows estimated to be spent to develop the Company's share of proved undeveloped properties through March 31, 2023 are $12,009,331.

Income tax expense is computed based on applying the appropriate statutory tax rate to the excess of future cash inflows less future production and development costs over the current tax basis of the properties involved, less applicable carryforwards.

The future net revenue information assumes no escalation of costs or prices, except for oil and natural gas sales made under terms of contracts which include fixed and determinable escalation. Future costs and prices could significantly vary from current amounts and, accordingly, revisions in the future could be significant.

The current 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 2018 were $50.63 per bbl of oil and $3.031 per mcf of natural gas. The average prices used for fiscal 2017 were $43.88 per bbl of oil and $2.561 per mcf of natural gas.

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first day of the month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves, less estimated future expenditures (based on year end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rate to the difference.

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 proved oil and gas properties.

The following information is based on the Company’s best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of March 31, 2018 and 2017 in accordance with ASC 932, “Extractive Activities – Oil and Gas” which requires the use of a 10% discount rate. This information is not the fair market value, nor does it represent the expected present value of future cash flows of the Company’s proved oil and gas reserves.

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

	March 31	
	2018	2017
Future cash inflows	$77,221,000	$110,778,000
Future production costs and taxes	(20,080,000)	(27,267,000)
Future development costs	(12,009,000)	(28,809,000)
Future income taxes	(6,413,000)	(13,386,000)
Future net cash flows	38,719,000	41,316,000
Annual 10% discount for estimated timing of cash flows	(19,843,000)	(22,233,000)
Standardized measure of discounted future net cash flows	$18,876,000	$19,083,000

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

	March 31 2018	2017
Sales of oil and gas produced, net of production costs	$(1,580,000)	$(1,459,000)
Net changes in price and production costs	6,967,000	1,849,000
Changes in previously estimated development costs	16,196,000	970,000
Revisions of quantity estimates	(23,969,000)	(404,000)
Net change due to purchases and sales of minerals in place	(1,744,000)	(2,380,000)
Extensions and discoveries, less related costs	1,240,000	6,994,000
Net change in income taxes	3,057,000	(3,959,000)
Accretion of discount	2,527,000	1,612,000
Changes in timing of estimated cash flows and other	(2,901,000)	1,962,000
Changes in standardized measure	(207,000)	5,185,000
Standardized measure, beginning of year	19,083,000	13,898,000
Standardized measure, end of year	$18,876,000	$19,083,000

16. Subsequent Events

On May 7, 2018, the Company agreed to a three year lease for its new principal office space located at 415 West Wall, Suite 475, Midland, Texas 79701. The lease commences on May 15, 2018 and expires on May 31, 2021.

INDEX TO EXHIBITS

Exhibit

Number

3.1	Restated Articles of Incorporation of Mexco Energy Corporation filed as Exhibit 3.1 to the Company's Annual Report on Form 10-K dated June 24, 1998, and incorporated herein by reference.
3.2	Amended Bylaws of Mexco Energy Corporation as amended on September 13, 2011 filed as Exhibit 3.1 to the Company's Current Report on Form 8-K dated September 14, 2011, and incorporated herein by reference.
10.1	2009 Employee Incentive Stock Plan of Mexco Energy Corporation filed as Exhibit A to the Company's Proxy Statement on Form 14C dated July 15, 2009, and incorporated herein by reference.
10.2	Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.2 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.3	First Amendment to Loan Agreement dated December 28, 2009 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.3 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.4	Second Amendment to Loan Agreement dated March 1, 2010 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.4 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.5	Third Amendment to Loan Agreement dated September 30, 2010 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.5 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.6	Fourth Amendment to Loan Agreement dated October 22, 2010 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.6 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.7	Fifth Amendment to Loan Agreement dated December 28, 2011 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.7 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.8	Sixth Amendment to Loan Agreement dated October 22, 2012 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.8 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.

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10.9	Seventh Amendment to Loan Agreement dated October 25, 2013 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.9 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.10	Eighth Amendment to Loan Agreement dated September 10, 2014 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.10 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.11	Ninth Amendment to Loan Agreement dated February 13, 2015 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.11 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.12	Tenth Amendment to Loan Agreement dated March 31, 2016 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.12 to the Company's Annual Report on Form 10-K dated June 27, 2017, and incorporated herein by reference.
10.13	Eleventh Amendment to Loan Agreement dated March 8, 2017 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008, and incorporated herein by reference.
14.1	Code of Business Conduct and Ethics of Mexco Energy Corporation filed with the Company's Quarterly Report on Form 10-Q filed on November 15, 2004, and incorporated herein by reference.
21.1	Subsidiaries of Mexco Energy Corporation
23.1	Consent of Weaver and Tidwell, L.L.P., Independent Registered Public Accounting Firm
23.2	Consent of Grant Thornton LLP, Independent Registered Public Accounting Firm
23.3	Consent of Russell K. Hall & Associates, Inc., 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 Russell K. Hall & Associates, Inc., Independent Petroleum Engineering Firm