Doxa Energy Ltd.

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Management Discussion and Analysis

For the period ended March 31, 2014
(Expressed in U.S. Dollars)

Overview

The following Management's Discussion and Analysis ("MD&A"), prepared as of May 29, 2014, should be read together with the unaudited condensed consolidated financial statements for the period ended March 31, 2014 and related notes attached thereto, which are prepared in accordance with International Financial Reporting Standards, ("IFRS"). The Company's functional currency is the U.S. dollar; the Canadian parent company's functional currency is the Canadian dollar. All amounts are stated in U.S. dollars unless otherwise indicated.

The reader should also refer to the audited consolidated financial statements for the year ended December 31, 2013 and 2012, found filed on SEDAR.

Additional information related to the Company is available for view on SEDAR at www.sedar.com, and the Company website www.doxaenergy.com.

Forward Looking Statements and Risk Factors

The forward-looking information in this MD&A is based on the conclusions of management. The Company cautions that due to risks and uncertainties, actual events may differ materially from current expectations. With respect to the Company's operations, actual events may differ from current expectations due to economic conditions, new opportunities, changing budget priorities of the Company or other factors.

Further information regarding these and other factors which may cause results to differ materially from those projected in forward-looking statements are included in the Company's filings with securities regulatory authorities. The Company does not undertake to update any forward-looking statement that may be made from time to time by the Company or on its behalf, except in accordance with applicable securities laws.

GLOSSARY OF ABBREVIATIONS

BBL	barrel
BOPD	barrels of oil per day
BOE	barrels of oil equivalent(1)
BOEPD	barrels of oil equivalent per day
MCF	1,000 cubic feet of natural gas
MCFD	1,000 cubic feet of natural gas per day

(1) BOE conversion ratio of 6 MCF: l BBL is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation.

(Expressed in U.S. Dollars)

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of units (or metric units).

To Convert From	To	Multiply By
MCF	Cubic metres	28.317
Cubic metres	Cubic feet	35.494
BBLs	Cubic metres	0.159
Cubic metres	Bbls	6.292
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

DESCRIPTION OF BUSINESS

Doxa Energy Ltd. (the "Company" or "Doxa") is a Canadian junior oil and gas company with its offices in Vancouver, B.C., and Fort Worth, Texas, and its shares are listed for trading on the TSX Venture Exchange under the symbol **DXA,** and the OTCQX under the symbol **DXAEF**. Its head office is found at Suite 1450 – 700 West Georgia Street, Vancouver, B.C., V7Y 1K8. The Company is engaged primarily in exploration for, and production of, petroleum and natural gas reserves in Oklahoma and Texas, USA.

Management is actively looking for additional oil and gas projects in North America and internationally. Management has experience evaluating and financing oil and gas projects and anticipates expanding the Company's activities through acreage acquisitions, as well as exploratory and development drilling of wells on its existing and acquired properties.

Oil and Gas Properties

<u>Mississippian Lime Play, Oklahoma</u>

On July 8, 2011, the Company acquired a 20% working interest in a Mississippian Lime Play project, consisting of approximately 17,710 acres (3,542 net) of oil and gas leasehold covering lands in Alfalfa, Garfield, Grant, Kay and Woods Counties, Oklahoma. 349 acres were sold or otherwise divested of in 2013. As of December 31, 2013 Doxa had sold or otherwise divested of approximately 706 total net acres of leasehold, and allocated just over 340 acres to drilling and producing well units, leaving 2,494 net acres, more or less, in undeveloped lease holdings, at a net cost to the Company of approximately $2,287,600.

As mentioned above, Doxa recently announced that in late 2013 it closed the sale of various leases within its Mississippian Lime Play project, bringing its total number of acres sold to just over 700 net acres out of its original holdings. Included in the sales were three wells then in the process of being drilled, completed and/or had recently commenced producing. The Company received total proceeds of approximately US$1.2mil as a result of these sales, which it used to reduce debt and fund ongoing operations, including the new projects. As previously reported, Doxa's average cost of acquisition per acre in the Mississippian Play totals about $760 per acre, while the calculated average price received for the noted sales of leasehold is $1,454 per acre. The proceeds included reimbursement for out-of-pocket costs associated with the included wells.

Though the Mississippian Lime Play has been producing across northern Oklahoma for decades, horizontal drilling and the application of staged fracture stimulation began in 2010. Chesapeake Energy Corp, SandRidge Energy, Inc. ("SandRidge") and Eagle Energy initially developed the Play, though SandRidge is the designated operator of most wells the Company has participated in to date.

As previously reported, most of Doxa's acreage is situated within two (2) of the Oklahoma counties, being Alfalfa and Grant. According to its November 14, 2013 Investor Presentation, SandRidge has drilled 940 horizontal wells in the Play as of September 30, 2013, with 616 well situated in a six (6) county "focus area" where they have elected to concentrate development of the play, which includes both Alfalfa and Grant Counties, where almost all of Doxa's wells have been drilled. These focus areas are described by SandRidge as having been de-risked, resulting in more predictable well results. Based on the current SandRidge type curve parameters, wells drilled within the focus area are projected to achieve an average 45% *IRR (*Internal Rate of Return), and a net present value per well of approximately $2.2mil (PV10) for each proved undeveloped location it generates, based on fixed Nymex strip pricing as of November 11, 2013. Single well estimated ultimate recovery per well, based on SandRidge' 2013 type well is projected at 368 MBOE with estimated drilling and completion costs of $2.95mil. At this time Doxa is unaware as to whether or not the aforementioned volumes and estimates pertaining to the Mississippian Lime Play are NI 51-101 compliant. The foregoing is set forth because Doxa has limited third party engineering evaluation covering its interests, and the potential future development thereof. Doxa's overall well results are not meeting original expectations of management, and appear in the early stages, to be less favorable than that projected by SandRidge. For these reasons, Doxa intends to limit its participation in new wells to a reduced level. On this basis, Doxa management expects that less than 1/2 of its remaining net acres will warrant development.

As at March 31, 2014 the Company had invested in 27 gross, or 0.84 net completed wells, excluding 3 active wells assigned to a third party buyer in connection with an acreage sale. The Company has invested approximately US$3.57mil in drilling and completing the 27 wells, which as of March 31, 2014 were collectively generating approximately $55,300 in revenue per month after deduction for royalty and taxes. Approximately 353 net acres of leasehold has been allocated to producing wells. During the first quarter 2013, completed Mississippian wells produced an average of approximately 14 barrels of oil per day (BOPD) and 90 MCF of natural gas per day (MCFPD), or 28 barrels of oil equivalent per day (BOEPD) per well, net to the company. One of the completed wells continues to be shut-in pending further evaluation and operations.

In addition to the foregoing, as of this date, the Company is participating in an additional well currently being completed. Results of the ongoing activities will be reported at a later date.

<u>3D Seismic Project, Bee and Goliad Counties, Texas</u>

During 2010, the Company acquired and currently owns a 30% working interest in the Sarco Creek seismic project covering approximately 26,880 acres in Goliad and Bee Counties, Texas. The Company participated in a proprietary 3D seismic program which was completed during 2011. During the year ended December 31, 2013, Doxa participated in three wells drilled to approximately 5,500 feet. The wells failed to encounter commercial quantities of oil or gas, and were deemed dry holes. Re-evaluation of the geological/geophysical pertaining to this project is ongoing, and management expects to commence an additional well in third quarter, 2014 and subject to favorable results, a subsequent well later in the fourth quarter.

<u>Peeler Ranch Area, Atascosa County, Texas</u>

During 2010, Doxa Energy Ltd. acquired a 20% working interest (15% net revenue interest) in the Peeler Ranch Eagle Ford Shale Prospect which covers approximately 2,005.9 acres in Atascosa County, Texas.

Two horizontal wells have been drilled on the prospect, being the Peeler Ranch No. 1-H, which was completed in March, 2011, when the well commenced initial production. The well is currently producing 15 BOPD. An impairment test performed at December 31, 2011, based on the NI 51-101 reserves report resulted in the Company booking an impairment of $2,084,336 against the capitalized costs of the Peeler project.

Drilling of the second well on the Peeler project, the Peeler Ranch No. 2-H was commenced in June, 2011. The Company sold 10.52% out of its 20% interest in the Peeler Ranch No. 2-H in order to assist in financing further development of its 9.4796% retained interest. The Peeler Ranch No. 2-H was completed in January, 2012 and after a 19 stage fracture stimulation, placed on production in February, 2012.

In order to focus its efforts and resources on the continuing development of its interests in the Mississippian Lime and other conventional projects it is pursuing, the Company decided to divest of its remaining undeveloped holdings in the Eagle Ford Shale Play. In 2012, the Company sold its remaining undeveloped Eagle Ford Shale Play acreage, the results of which have been previously reported. Doxa retained its existing interests under various other developed Eagle Ford Shale leases and wells, including the Peeler Ranch No. 1-H and 2-H in Atascosa County, Texas, and the Epley No. 1-H well in adjacent McMullen County.

<u>County Line Prospect, McMullen County, Texas</u>

In 2011, Doxa acquired a 14.0625% leasehold working interest and a respective 10.4867% net revenue interest under approximately 1,412 gross acres comprising the County Line Prospect. On January 12, 2011, drilling operations were commenced on the initial test well on the prospect, being the Martin-State Gas Unit No.1. This initial well was drilled vertically to a total depth of 11,800 feet, testing various Wilcox formation sands below 7,500 feet. Based on the favorable results of log evaluation, the well is completed in various intervals from 9,900’ to 10,500’. In June, 2011, the well was placed on-line and is currently producing approximately 745 MCFD, along with 3 BCPD. Hurd Enterprises, Ltd. of San Antonio, Texas, is the designated Operator of this prospect.

<u>County Line North Prospect, McMullen County, Texas</u>

Also in 2011, Doxa closed on the acquisition of a 16.70625% working interest before payout (reverting to 12.5% after payout) in the County Line North Project, McMullen County, Texas, a new venture targeting various Wilcox formation zones of interest. The County Line North Project, operated by Hurd Enterprises, Ltd., of San Antonio, Texas, is a conventional gas condensate prospect which is situated on an initial 280 acre block of leases. Drilling of the Kynette No. 1, the initial well on this project was commenced on June 13, 2011 and completed on August 22, 2011 at its permitted depth of 10,500’. The well commenced production in October, 2011 and is currently producing at a rate of approximately 1,175 MCFD and 17 BCPD. This project is situated approximately 2 miles northeast of the recently completed Martin-State Unit No. 1 well (see above).

<u>New Beilau Prospect, Colorado County, Texas</u>

The Company also owns a 6.25% working interest in the New Beilau Prospect in Colorado County, Texas. Drilling operations on the initial well on this conventional normal pressured Wilcox prospect, the Koehn Unit No. 1 well were completed in August, 2010. A total depth of 10,227’ was reached, and based on favorable well log evaluation of the objective Wilcox formation, 4 ½” production casing was run and cemented. Completion operations and facility construction were completed in November, 2010. The well is marginally productive and Dynamic Production, Inc. of Fort Worth, Texas, designated operator of the project, is planning a workover aimed at increasing productivity of the well.

Doxa also participated in the second well drilled on the above described New Beilau Prospect, being the Koehn Unit No. 2. The Koehn Unit No. 2 well was drilled and successfully completed in October, 2012, and is completed in the Wilcox formation producing from perforations at 9,618-68 feet. The well is currently producing 50 BOPD and 400 MCFD. Doxa participated for a 12.5% working interest at a total estimated cost of $212,000, subject to the terms of a governing joint operating agreement. Company management is considering participation in at least 1 additional well on this project.

An impairment test performed at December 31, 2011, based on the NI 51-101 reserves report resulted in the Company booking an impairment of $35,924 against the capitalized costs of the Koehn Unit No. 1 well. Based on the 2012 impairment test, the 2011 impairment of $35,924 was reversed.

Epley Project, McMullen County, Texas

In 2010 Doxa acquired a 15% working interest (11.25% net revenue interest) in the 640 acre Epley Project in McMullen County, Texas, operated by San Isidro Development Company. Drilling operations on the horizontal well (the “Epley No. 1-H”) were commenced in June, 2010 targeting the gas condensate window of the Eagle Ford Shale formation below 11,000 feet. The Eagle Ford Shale was encountered at a true vertical depth of approximately 10,900 feet and a horizontal lateral was successfully drilled in excess of 4,000 feet. Following completion of a 15 stage fracture stimulation operation, initial sales of oil and gas commenced in November, 2010. Impairment tests performed at December 31, 2010 and December 31, 2011, based on the NI 51-101 reserves report resulted in the Company booking impairments of $1,950,084 and $84,694, respectively, against the capitalized costs of the Epley Project. The impairment test performed at December 31, 2012, resulted in a recovery of $19,837.

New Project Additions, Jackson and Webb Counties, Texas

During 2013 Doxa entered into definitive agreements providing for its participation in 3 new conventional exploration projects covering lands situated in Jackson and Webb Counties, Texas. Two of the projects are focused on the Queen City formation at depths above 6,000′ subsurface in areas which historically produce oil, and the third project will be targeting gas/condensate production from the expanded Yegua formation on the Gulf Coast. Furthermore, operations for drilling and evaluating initial test wells on two of the projects commenced in the fourth quarter 2013 and are ongoing. Each new project offers potential for development wells. As of December 31, 2013, 857 gross acres (124 net to Doxa) of leasehold interest had been acquired and efforts to acquire additional leases were ongoing. Doxa’s level of participation in the two Queen City projects vary from 15-28.5% before payout, and is set at 4.5% in the Yegua formation test, subject to certain terms and conditions set forth in the respective agreements. Drilling operations on 2 of the projects have been completed and based on favorable log and test results, as at March 31, 2014 completion operations had been commenced and ongoing. A third well is expected to be commenced in the third quarter of 2014 upon completion of leasing efforts. Additional details of all three projects will be released in the future upon completion of ongoing operations and leasing efforts.

OPERATIONS REVIEW

Selected Production Net to the Company

	Three months ended March 31		Year Ended December 31,	
	2014	2013	**2013**	2012
Gas - MCF	**43,699**	77,946	**292,052**	271,217
Oil - BBL	**2,691**	3,932	**13,246**	13,230
Total - BOE	**9,975**	16,923	**61,922**	58,433

Selected Revenue Net to the Company

	Three months ended March 31,			
	2014		2013	
	($000’s)	($/BOE)	($000’s)	($/BOE)
Oil and gas revenue	$448.1	$44.9	$658.4	$38.9
Severance taxes	(21.9)	(2.2)	(41.9)	(2.5)
Production expenses	(89.7)	(9.0)	(148.7)	(8.8)
Total $, $/BOE	$336.5	$33.7	$467.8	$27.6

(Expressed in U.S. Dollars)

Selected Annual Information

Year Ended December 31	2013	2012	2011
Total Revenues *	$2,240,020	$1,939,965	$1,208,580
Net Income (Loss)	(2,653,664)	294,832	(3,675,558)
Basic and Diluted Earnings (Loss) per share	(0.08)	0.01	(0.12)
Total Assets	5,561,866	9,581,190	7,926,437
Total Non-Current liabilities	2,838,760	3,190,306	1,971,290
Cash Dividends Declared per Share	$0.00	$0.00	$0.00

*Revenues presented net of severance taxes and transport

Summary of Quarterly Results

The following table sets forth a comparison of the revenues and net income (loss) for each of the Company's last eight quarters:

Quarter Ended	2014	2013				2012		
	31-Mar	31-Dec	30-Sep	30-Jun	31-Mar	31-Dec	30-Sep	30-Jun
Total Revenues	$448,088	$380,728	$664,229	$663,908	$658,428	$738,676	$434,383	$494,845
Net Income (Loss)	(203,956)	(2,072,613)	(4,691)	(427,350)	(149,010)	33,604	189,540	(42,426)
Earnings (Loss) per share	$(0.01)	$(0.06)	$(0.00)	$(0.01)	$(0.01)	$0.00	$0.01	$(0.01)

Performance Summary

Three months ended March 31, 2014:

For the three months ended March 31, 2014, the Company realized a net loss of $(203,956) as compared to net loss of $(149,010) for the same period in 2013. The loss per share was $(0.01) as compared to loss per share of $(0.01) for the same period in 2013. Earnings (Losses) before interest, taxes, depletion and amortization (EBITDA) for the period were $43,607 compared to $243,120 for the same period in 2013. The net income (loss) experienced by the Company fluctuates each quarter due to the timing of certain expenditures such as share-based payments which is expensed upon grant of stock options or as they vest. The net income (loss) can also fluctuate due to peripheral or incidental transactions or events such as a realized gain or a write-down or write-off of an asset.

The Company had gross revenue from oil and gas production from thirty two wells during the three month period of $448,088, as compared with $658,428 from twenty-seven wells for the same period in 2013. During the three months ended March 31, 2014, the Company had net production of 2,691 BBLS oil and 43,699 MCF gas compared with 3,932 BBLS oil and 77,946 MCF gas for the same period in 2013. The average price of oil realized during the current period was $88.02 per BBL and for gas $4.61 per MCF compared to $98.05 per BBL and $3.50 per MCF for the prior year period.

The Company had exploration expenses for the period of $281,144 as compared with $201,577 in 2013.

Advertising and promotion expenses for the period were $283 as compared to $493 in 2013. The decrease in advertising and promotion expenses during the period is due to the decision by management to minimize expenditures in this category.

Filing fees and shareholder services for the three month period were $6,676 as compared to $7,573 in 2013. Filing fees and shareholder services fluctuates depending on activity during the period.

Travel expenses for the period were $Nil as compared to $9,721 in 2013. Travel expense will fluctuate each quarter depending on the travel activity of management and staff.

Interest expense on long-term debt for the period was $59,337 as compared to $81,730 in 2013.

Professional fees for the period were $927 as compared to $Nil in 2013. Professional fees include legal, accounting and auditing fees. Professional fees fluctuate each quarter depending on activity.

Liquidity and Capital Resources

The Company ended the period with $78,122 (2013 - $113,599) cash and cash equivalents and negative working capital of $(1,665,710) (2013 - $(1,928,330).

Net cash from operating activities for the period ended was $(36,503) as compared to net cash of $(519,668) from operating activities in 2013.

Net cash used in investing activities for the period ended was $74,303 as compared to $(580,198) during 2013.

Net cash provided from (used in) financing activities for the period ended was $(35,000) as compared to $780,000 during 2013.

The Company does not have sufficient funds to meet its liabilities and investment obligations for the ensuing twelve months as they fall due. In assessing whether the going concern assumption is appropriate, Management takes into account all available information about the future, which is at least, but not limited to, twelve months from the end of the reporting period.

The Company's ability to continue operations and fund its liabilities is dependent on management's ability to secure additional financing from either debt or equity, or from asset divestment opportunities. In this regard, Management has secured a revolving line of credit in the face amount of $5,000,000 with a borrowing base of $3,000,000. Management is pursuing such additional sources of financing and, while it has been successful in doing so in the past, there can be no assurance it will be able to do so in the future.

Critical Accounting Estimates

The Company's accounting policies are presented in Note 3 of the accompanying financial statements. The preparation of financial statements in accordance with IFRS requires management to select accounting policies and make estimates. Such estimates may have a significant impact on the financial statements. Actual amounts could differ materially from the estimates used and, accordingly, affect the results of the operations.
These include:

- the carrying values of property and equipment;
- the valuation of share-based payments;
- the depletion and amortization of property and equipment;
- the valuation of deferred income tax assets;
- the provision for decommissioning liabilities;
- the collectability of accounts receivable; and
- the determination of environmental obligations

Key Accounting Policies

a) Revenue Recognition

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline. Revenue is measured net of discounts customs duties and royalties. With respect to the latter, the entity is acting as a collection agent on behalf of others.

Tariffs and tolls charged to other entities for use of pipelines and facilities owned by the Company are recognized as revenue, as they accrue in accordance with the terms of the service or tariff and tolling agreements.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

b) Petroleum Properties and Production Equipment

(i) Pre-exploration expenditures

Expenditures made by the Company before acquiring the legal right to explore in a specific area do not meet the definition of an asset and therefore are expensed by the Company as incurred.

(ii) Exploration and evaluation expenditures

Costs incurred once the legal right to explore has been acquired are capitalized as exploration and evaluation assets. These costs include, but are not limited to, exploration license expenditures, leasehold property acquisition costs, evaluation costs, including drilling costs directly attributable to an identifiable well and directly attributable general and administrative costs. These costs are accumulated in cost centers by property and are not subject to depletion until technical feasibility and commercial viability has been determined.

Exploration and evaluation assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are grouped together with developing and producing assets and are tested at an aggregated cash-generating unit ("CGU") level. The Company evaluates the geography, geology, production profile and infrastructure of its assets in determining its CGUs. Doxa's CGUs are generally composed of significant development areas. The Company reviews the composition of its CGUs at each reporting date to assess whether any changes are required in light of new facts and circumstances.

The technical feasibility and commercial viability of extracting a petroleum or natural gas resource is considered to be determinable when proved and probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved and probable reserves have been discovered. Upon determination of proved and probable reserves, exploration and evaluation assets attributable to those reserves are tested for impairment and reclassified from exploration and evaluation assets to petroleum and natural gas properties.

(iii) Other intangible costs

Costs of data purchased to formulate strategy for license applications, such as seismic data, and asset purchases are accumulated and capitalized as other intangible assets to the extent that they are incurred prior to obtaining related licenses and do not relate to a field with proven reserves attributed.

(iv) Developing and production costs

Items of property and equipment, which include petroleum and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount.

When significant parts of an item of property and equipment, including petroleum and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property and equipment, including petroleum and natural gas properties, are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized net within the statements of operations and comprehensive loss.

(v) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property and equipment are recognized as petroleum and natural gas properties only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in comprehensive income (loss) as incurred. Such capitalized petroleum and natural gas properties generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property and equipment are recognized in comprehensive income (loss) as incurred.

(vi) Depletion and depreciation

Depletion of petroleum and natural gas properties is provided using the unit-of-production method based on production volumes in relation to total estimated proved reserves as determined annually by independent engineers.

Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil. Costs are only depleted once production in a given area begins.

Calculations for depletion and depreciation of production equipment are based on total capitalized costs plus estimated future development costs of proved and undeveloped reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced.

Proved reserves are estimated using independent reserve engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids, which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- A reasonable assessment of the future economics of such production;

- A reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- Evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proved if supported by either actual production or conclusive formation tests.

The area of reservoir considered proved includes:

(i) that portion delineated by drilling and defined by as-oil and/or oil-water contacts, if any, or both; and
(ii) immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

Depletion and depreciation for other equipment is recognized in profit or loss on a declining balance basis with the following annual rates:

Office equipment	20%
Computer equipment	45%

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

c) Impairment of non-financial assets

Exploration and evaluation assets are assessed for impairment when they are reclassified to developing and producing assets, as petroleum and natural gas properties, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the CGU). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

Fair value less costs to sell is determined to be the amount for which the asset could be sold in an arm's length transaction. Fair value less costs to sell can be determined by using an observable market or by using discounted future net cash flows of proved and probable reserves using forecasted prices and costs. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU.

At December 31, 2013, the Company calculated the impairment test using NYMEX strip prices for oil and gas and future prices based on a benchmark commodity price forecast provided by the Company's independent reserve evaluators.

At December 31, 2013, an impairment of $24,279 was determined on the Epley Prospect, $116,456 was determined on the Peeler Prospect, $133,052 was determined on the Martin State Prospect, and $1,157,359 was determined on the Mississippian Project, for a total impairment of $1,431,146. In addition to the impairment on producing assets, an impairment of $987,017 was taken on the leasehold cost on the Mississippian Project.

Off Balance Sheet Arrangements

There are no off balance sheet arrangements to which the Company is committed.

Related Party Transactions

During the period ended March 31, 2014, the Company was charged legal fees of $927 (December 31, 2013 - $8,224) by S. Paul Simpson Law Corp., a law firm of which an officer of the Company is an employee.

At March 31, 2014, the Company has CDN$1,884,904 in loans payable owing to Armada, a Company controlled by the chairman of the Company.

(Expressed in U.S. Dollars)

At March 31, 2014, the Company has CDN$554,384 in loans payable owing to Harvco, a Company controlled by the president and director of the Company.

Capital Stock, Options, Warrants and Escrowed Shares:

a) Common shares issued and outstanding as at March 31, 2014 – 33,980,141 common shares.

b) Options outstanding as at March 31, 2014 – 2,816,000 stock options

c) Warrants outstanding as at March 31, 2014 – 3,835,286 warrants

List of Officers and Directors

John D. Harvison	Director, President and CEO, Ft. Worth, Texas
G. Arnold Armstrong	Director and Chairman, Vancouver, BC
Mark Bronson	Director and CFO, Ft. Worth, Texas
Gerald Graham	Director, President of Doxa Energy US, Inc. Fort Worth, Texas
Jonathon Weiss	Director, Ft. Worth, Texas
Dan Frederiksen	Director, Vancouver, BC
Paul McKenzie	Director, Vancouver, BC
Shauna Hartman	Corporate Secretary, Surrey, BC

FINANCIAL INSTRUMENTS

Details of the Company's financial instruments, management's assessment of their related risks and details of management of those risks are as follows:

Financial Risk Management

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Company's financial instruments consist of cash, accounts receivable and accrued liabilities.

The fair values of cash, accounts receivable and accrued liabilities approximate their book values because of the short-term nature of these instruments.

Financial Instrument Risk Exposure

The Company is exposed in varying degrees to a variety of financial instrument related risks. The Board approves and monitors the risk management processes.

Credit Risk

The Company's only exposure to credit risk is on its bank accounts and trade receivables. Bank accounts are with highly rated Canadian and US financial institutions.

Liquidity Risk

The Company has sufficient capital in order to meet short-term business requirements, taking into account the Company's holdings of cash. The Company's cash is invested in business accounts which are available on demand.

Market Risk

The only significant market risk exposure to which the Company is exposed is interest rate risk. The Company's bank account earns interest income at variable rates. The fair value of its portfolio is relatively unaffected by changes in short-term interest rates. The Company's future interest income is exposed to short-term rate fluctuations.

Exchange Risk

As at March 31, 2014, some of the Company's cash was held in Canada in Canadian dollars and some was held in the US in US dollars. As a result, the Company is subject to fluctuations in exchange rates.

Risk Factors

The Company is in the business of acquiring, exploring and, if warranted, developing and exploiting natural resource properties in North America. Due to the nature of the Company's proposed business and the present stage of exploration of its oil and gas properties the following risk factors, among others, will apply:

Exploration, Development and Operating Risks
The exploration for and development of oil and gas reserves involves significant risks which even a combination of careful evaluation, experience and knowledge may not eliminate. Few properties that are explored are ultimately developed into producing wells. Major expenses may be required to locate and establish petroleum reserves, to develop processes and to construct battery facilities at a particular site. It is impossible to ensure that the exploration or development programs planned by the Company will result in a profitable commercial oil operation. Whether an oil reserve will be commercially viable depends on a number of factors, some of which are: the particular attributes of the reserve, such as quantity and quality of the minerals and proximity to infrastructure; oil prices, which are highly cyclical; and government regulations, including regulations relating to prices, taxes, royalties, land tenure, land use, and environmental protection.

The exact effect of these factors cannot be accurately predicted but could have a material adverse effect upon the Company's operations.

Oil and gas operations generally involve a high degree of risk. The operations of the Company are subject to all the hazards and risks normally encountered in the exploration, development and production of oil and gas, including unusual and unexpected geologic formations, seismic activity, rock bursts, cave-ins, flooding and other conditions involved in the drilling and removal of material, any of which could result in damage to, or destruction of other producing facilities, damage to life or property, environmental damage and possible legal liability.

Dependence on the Operator and Operational Risks
The Company holds a minority interest in its oil and gas properties and is not the operator of them. As such, the Company is dependent on the operator of these properties for further development and management of these properties. Operational risks in the oil and gas industry include exploration and reserve estimate risks, costs and availability of services and materials, premature reservoir declines, blowouts, well bore collapse, equipment failure and other accidents and adverse weather conditions. The Company is able to obtain material information regarding the operations of these properties when necessary, and is confident that the operations on these properties are carried out in keeping with industry standards.

Political Stability and Government Regulation Risks
The operations of the Company are currently conducted in North America, and as such, the operations of the Company are not exposed to severe uncertainties. Operations may be affected in varying degrees by government regulations with respect to, but not limited to, restrictions on production, price controls, export controls, currency remittance, income taxes, expropriation of property, foreign investment, maintenance of claims, environmental legislation, land use, land claims of local people, water use and safety. Failure to comply strictly with applicable laws, regulations and local practices relating to mineral rights applications and tenure could result in loss, reduction or expropriation of entitlements.

Insurance and Uninsured Risks
The business of the Company is subject to a number of risks and hazards in general, including adverse environmental conditions, industrial accidents, labor disputes, unusual or unexpected geological conditions, ground or slope failures, changes in the regulatory environment and natural phenomena such as inclement weather conditions and floods.

Such occurrences could result in damage to oil properties or facilities and equipment, personal injury or death, environmental damage to properties of the Company or others, and monetary losses and possible legal liability.

Although the Company may maintain insurance to protect against certain risks in such amounts as it considers being reasonable, its insurance may not cover all the potential risks associated with the Company's operations. The Company may also be unable to maintain insurance to cover these risks at economically feasible premiums. Insurance coverage may not be available or may not be adequate to cover any resulting liability.

Moreover, insurance against risks such as environmental pollution or other hazards as a result of exploration and production is not generally available to the Company or to other companies in the oil and gas industry on acceptable terms. The Company might also become subject to liability for pollution or other hazards which it may not be insured against or which the Company may elect not to insure against because of premium costs or other reasons. Losses from these events may cause the Company to incur significant costs that could have a material adverse effect upon its financial performance and results of operations.

Environmental Risks and Hazards
All phases of the Company's operations are subject to environmental regulation in the various jurisdictions in which it operates. These regulations mandate, among other things, the maintenance of air and water quality standards and land reclamation. They also set forth limitations on the generation, transportation, storage and disposal of waste. Environmental legislation is evolving in a manner that will require stricter standards and enforcement and involve increased fines and penalties for non-compliance, more stringent environmental assessments of proposed projects, and a heightened degree of responsibility for companies and their officers, directors and employees. There is no assurance that future changes in environmental regulation, if any, will not adversely affect the Company's operations. Environmental hazards may exist on properties in which the Company holds interests which are unknown to the Company at present and which have been caused by previous or existing owners or operators of the properties.

Forward Looking Statements

Except for statements of historical fact relating to the Company, certain information contained herein constitutes forward-looking statements. Forward-looking statements are frequently characterized by words such as “plan”, “expect”, “project”, “intend”, “believe”, “anticipate” and other similar words, or statements that certain events or conditions “may” or “will” occur. Forward-looking statements are based on the opinions and estimates of management at the date the statements are made, and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. These factors include the inherent risks involved in the exploration and development of oil and gas properties, the uncertainties involved in interpreting drilling results and other ecological data, fluctuating oil and gas prices, the possibility of project costs overruns or unanticipated costs and expenses, uncertainties relating to the availability and costs of financing needed in the future and other factors. The Company undertakes no obligation to update forward-looking statements if circumstances or management's estimates or opinions should change. The reader is cautioned not to place undue reliance on forward-looking statements.