PetroShale

Calgary • Denver

Annual Information Form
Year Ended December 31, 2014

March 30, 2015

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APPENDICES

GLOSSARY OF TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Alameda means Alameda Energy Inc.

Algonquin means Algonquin Oil & Gas Limited.

Board of Directors means our board of directors.

GEL means GEL Exploration, our wholly owned subsidiary.

Mondak US means Mondak (US), Inc., the previous corporate name of PetroShale US.

NDIC means the North Dakota Industrial Commission.

PetroShale, **we**, **us, our** or the **Corporation** means PetroShale Inc. and where the context requires, means us and all our controlled entities on a consolidated basis, and where the context requires, also means our predecessor issuers, Mondak Petroleum Inc., Algonquin and their controlled entitles on a consolidated basis.

PetroShale US means PetroShale (US), Inc., our wholly owned subsidiary incorporated under the laws of Delaware.

Shareholders mean holders of our Common Shares.

Slawson means Slawson Exploration Company.

Independent Engineering

COGE Handbook means Canadian Oil and Gas Evaluation Handbook.

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

McIntosh means Jim McIntosh Petroleum Engineering Ltd.

McIntosh Report means the report prepared by McIntosh dated March 13, 2015 evaluating the crude oil, natural gas liquids reserves attributable to our properties located in Canada as at December 31, 2014.

NSAI means Netherland, Sewell & Associates, Inc., worldwide independent petroleum consultants.

NSAI Report means the report prepared by NSAI dated February 16, 2015 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to all of our oil and natural gas assets located in Montana and North Dakota, United States as at December 31, 2014.

NI 51-101 means National Instrument 51-101– *Standards of Disclosure for Oil and Natural Gas Activities*.

Reserve Reports means collectively the McIntosh Report and the NSAI Report.

Securities

Common Non-Voting Shares means our common non-voting shares as presently constituted.

Common Shares means our common shares as presently constituted.

Preferred Shares means our class A preferred shares as presently constituted.

Other

IFRS means International Financial Reporting Standards.

United States or **US** means the United States of America.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Bbls/d	barrels per day	Bcf	billion cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels of oil	MMbtu	million British Thermal Units
NGLs	natural gas liquids	GJ	gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
m^3	cubic metres
MBoe	thousand barrels of oil equivalent.
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars
$MM	millions of dollars

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. References herein to "$", $Cdn or "dollars" are to Canadian dollars and references herein to $US or "US dollars" are to United States dollars. Unless otherwise indicated, all financial information herein has been presented in Canadian dollars in accordance with IFRS.

CONVERSIONS

The following table sets forth certain 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	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

BARREL OF OIL EQUIVALENCY

The term "Boe" may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf: 1 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. **Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value**.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to our future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology. In addition, there are forward-looking statements in this Annual Information Form under the headings "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our business plan and strategy, the effect of negotiation of contracts; potential acquisitions and our acquisition plans and strategy; "*Statement of Reserves Data and Other Oil and Natural Gas Information*" as to our reserves and future net revenue from our reserves, income taxes and pricing, exchange and inflation rates. The development of our proved undeveloped reserves and probable undeveloped reserves, future developments costs, our plans to fund future developments costs through a combination of internally generated cash flow, debt and equity issuances and anticipated funding costs; and as to our exploration and development plans and opportunities, anticipated land expiries, hedging and marketing policies, abandonment and reclamation obligations, tax horizon and future production; and "*Dividend Policy*" as to our dividend policy and the future payment of dividends.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- well completions and the timing thereof;
- the performance characteristics of our oil and natural gas properties;
- expectation of future production rates, volumes and product mixes;

- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions, development and optimization;
- treatment under governmental regulatory regimes and tax laws;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production and timing of results therefrom;
- fluctuations in depletion, depreciation and accretion rates;
- expectations regarding the costs and timing to drill and complete oil and natural gas wells;
- expectations regarding the costs to produce and transport our oil and natural gas to markets;
- expected changes in regulatory regimes in respect of royalty rates, production taxes and regulatory improvements and the effects of such changes;
- expectations of operating costs, costs to abandon and reclaim well sites and related production and transportation infrastructure; and
- plans to expand recovery from certain of our properties.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- volatility in market prices for oil and natural gas and foreign exchange rates;
- operational risks and liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- uncertainties in our plans and the plans of the operators of our oil and natural gas properties in regard to the timing of development programs;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- the accuracy of oil and natural gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; commodity prices and royalty and production tax regimes; availability of skilled labour; timing and amount of capital expenditures; future currency exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with IFRS requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.** See "*Risk Factors*".

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

NON-IFRS MEASURES

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "netback" in this Annual Information Form is not a recognized measure under IFRS. We use "netback" as a key performance indicator and it is used by us to evaluate the operating performance of our petroleum and natural gas assets and is determined by deducting royalties and production and operating expenses from petroleum and natural gas revenue. Readers are cautioned however that this measure should not be construed as an alternative to net earnings (loss) or cash flow from operating activities determined in accordance with IFRS as an indication of our performance.

PETROSHALE INC.

General

We are a junior oil and natural gas company engaged in the acquisition, development and consolidation of interests primarily in the North Dakota Bakken. We incorporated as "Mondak Petroleum Inc." under the *Business Corporations Act* (Alberta) on November 9, 2011.

On March 8, 2012 we completed a reverse takeover of Algonquin Oil & Gas Limited pursuant to the Algonquin Arrangement. Following which we filed Articles of Amendment to re-designate our Common Shares, to create the Common Non-Voting Shares and to make consequential amendments to the rights, restrictions, privileges and conditions attached to our Preferred Shares. Also on March 8, 2012, we filed Articles of Amendment to consolidate our Common Shares and Common Non-Voting Shares on a 10 for 1 basis and to change our name from Algonquin to "PetroShale Inc.".

On July 1, 2013 we amalgamated with our then wholly-owned subsidiary Mondak Petroleum Inc.

Our corporate head office is located at 3900, 350 – 7th Avenue T2P 3N9, our US head office is located at 1801 Broadway Suite 920, Denver, CO 80202 and our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Intercorporate Relationships

Currently, we have two wholly-owned subsidiaries, PetroShale US and GEL.

PetroShale US was incorporated under the laws of Delaware on November 10, 2011 under the name "Mondak Petroleum (US), Inc." and changed its name to "PetroShale (US), Inc." on April 4, 2012.

GEL was incorporated under the *Business Corporations Act* (Ontario) on May 23, 1961 and was acquired by us on June 5, 2000.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

Fiscal Year Ended June 30, 2013

Mr. M. Bruce Chernoff was appointed to our Board of Directors on September 4, 2012.

On October 17, 2012 we acquired our Melbby project comprised of certain oil and gas producing assets in Mountrail County, North Dakota in the Williston Basin. The acquisition had an effective date of August 1, 2012 and the purchase price of $4.0 million was funded by way of a combination of cash and debt. This acquisition was not considered a significant acquisition under National Instrument 51-102 – *Continuous Disclosure Obligations*.

On May 6, 2013 we appointed Mr. Evan Genaud as our Chief Executive Officer and on May 30, 2013 we appointed Mr. Tristan Farel as our Chief Financial Officer. In connection with Mr. Genaud's appointment, we conducted a private placement of 134,000 Common Shares to Mr. Genaud at a price of $0.29 per Common Share for gross aggregate proceeds of $38,860.

On May 17, 2013 we acquired our MJ Angus project comprised of approximately 105 net acres of land in NE McKenzie County, United States, including an average 1.5% working interest in 11 wells either recently completed or in the drilling process at the time of acquisition.

For more information on our properties see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Properties*" in this Annual Information Form.

Six Months Ended December 31, 2013

On August 19, 2013 we acquired 106 net leased acres in two overlapping 1280 acre drilling units within the Stockyard Creek Field in Williams County, North Dakota for a purchase price of US$934,000.

On October 31, 2013 Mr. Genaud resigned as our President and Chief Executive Officer and Mr. James Fair was appointed as our interim President and interim Chief Executive Officer.

On November 25, 2013 Mr. M. Bruce Chernoff was appointed as our Executive Chair and Chief Executive Officer, Mr. David Rain was appointed as our Chief Financial Officer and Mr. Tony Izzo was appointed as our Vice-President, Business Development. In addition to the changes to our management, Mr. John Haag resigned from our Board of Directors and Mr. Ken McCagherty was appointed to fill the vacancy. Concurrent with the change of management, we entered into a one year revolving acquisition credit facility. See "*Description of our Capital Structure*".

Year Ended December 31, 2014

During the year ended December 31, 2014, through several transactions, we purchased 2,442 net acres of oil and gas leases and producing properties with approximately 140 Boe/d of production. All of the transactions were in our core area within North Dakota. We paid an aggregate of US$32.8 million to complete these transactions which were funded by a combination of cash, credit facilities, and the private placement of common shares described below. In addition, we also participated in drilling 43 gross (3.3 net) wells in 2014 for a total capital expenditure of US$25.0 million.

On February 11, 2014 we changed our financial year end from June 30 to December 31.

In September of 2014, we secured a new senior credit facility with a major Canadian chartered bank. See "*Description of our Capital Structure*".

In January 2014, we entered into a subordinated loan agreement with our two largest shareholders providing a revolving line of credit. See "*Description of our Capital Structure*".

We completed a non-brokered private placement of 5 million common shares at $1.30 per share for gross proceeds of $6.5 million in June 2014. Proceeds were used to initially repay outstanding debt.

Recent Developments

On March 25, 2015 the borrowing base of our senior credit facility was increased to US$15.5 million and the renewal date was extended to March 24, 2016.

Significant Acquisitions

None of the acquisitions completed during the year ended December 31, 2014 qualified as significant transactions pursuant to Part 8 of National Instrument 51-102.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

We are a growing oil company engaged in the acquisition, development and consolidation of interests in the North Dakota Bakken. Our strategy focuses on acquiring leases in the most prolific areas of the Williston Basin where the resources and stacked pay zones are the most intense and which are operated by large, experienced and capable operators. We strive to acquire leases with pad drilling underway or imminent so that our capital is efficiently deployed into near-term results. By acquiring non-operated working interests in fields being developed by efficient operators, we manage risk and capital exposure while maximizing production, optimizing ultimate recoveries and enhancing rates of return.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and have experienced a marked decrease in the past few months. Commodity prices are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. In addition, the exploration and development of oil and natural gas reserves is dependent on access to areas where production is to be concluded. Seasonal weather variation including freeze-up and break-up, affect access in certain circumstances.

Ongoing Acquisition Activities

Potential Acquisitions

We evaluate potential acquisitions of all types of oil and natural gas and other energy related assets as part of our ongoing asset portfolio management program. We are normally in the process of evaluating and offering on several potential acquisitions at any one time which individually or together could be material and it is in the normal course of our business to routinely put offers on properties or acquisitions that fit within our business objectives.

Environment Policies

The oil and natural gas industry is subject to extensive controls and regulations governing its operations imposed by legislation enacted by various levels of government with respect to pricing and taxation of oil and natural gas, all of which should be carefully considered by investors in the oil and gas industry. Since these requirements apply to all operators in the oil and natural gas industry, it is not anticipated that our competitive position within the industry will be adversely affected in a manner materially different than they would affect other oil and gas companies of similar size. All legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Compliance with provincial, state and federal environmental legislation can require significant expenditures or operational restrictions. Breach of such requirements may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which have the potential for negative impacting earnings and corporate growth. We maintain an active list of our expected future expenditures to reclaim our properties to acceptable regulatory standards. This list is reviewed on an ongoing basis and the present value of these costs is recorded as a liability on our financial statements. The expected future obligation is not outside the norm for a company of our size and operations. At present, we believe, to the best of our knowledge, that we, and the operators of our non-operated properties, meet all existing environmental standards and regulations and have included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. We have internal procedures designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding with them.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business may be materially negatively affected in the remainder of 2015 by the renegotiation or termination of contracts or subcontracts other than our two credit facilities. See "*Description of our Capital Structure*".

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploration and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. Additionally, the area in which we seek to acquire assets and interests is a very competitive area of North Dakota and we are a smaller company than a majority of the players active in the same area. See "*Risk Factors – Competition*".

We strive to be competitive by maintaining financial flexibility, capitalizing on acquisitions and by utilizing current technologies to enhance optimization, development and operational activities.

Human Resources

As at December 31, 2014 we had 10 employees.

Material Restructuring Transactions

Within the three most recently completed financial years we completed the reverse takeover with Algonquin effective March 8, 2012. See "*PetroShale Inc. – General"*

Foreign Operations

We primarily conduct our business in the United States through PetroShale US and, as such, our business is dependent upon foreign operations and associated risks. See "*Risk Factors*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated March 13, 2015 with respect to our Canadian oil and gas assets and dated February 16, 2015 with respect to our United States oil and gas assets. The statement is effective as of December 31, 2014. The Report On Reserves Data By Independent Qualified Reserves Evaluators in Form 51-101F2 and the Report Of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices A and B, respectively to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon evaluations by NSAI and McIntosh with an effective date of December 31, 2014 as contained in the Reserve Reports. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The Reserve Reports have been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged NSAI to provide an evaluation of our proved and proved plus probable reserves in the United States and we engaged McIntosh to provide an evaluation of our proved and proved plus probable reserves in Canada and no attempt was made to evaluate possible reserves in either country.

Our reserves are in Canada, specifically the Province of Ontario and in the United States, specifically in North Dakota and Montana. **All financial information provided herein with respect to our Canadian reserves are in $Cdn, all financial information provided herein with respect to our United States reserves are in $US and all financial information provided herein with respect to our reserves in the aggregate are in $Cdn using the exchange rate in effect as at December 31, 2014 of $US1.00 = $1.16Cdn.**

We determined the future net revenue and present value of future net revenue after income taxes by using NSAI's and McIntosh's before income tax future net revenue and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different. Our financial statements for the period ended December 31, 2014 should be consulted for additional information regarding our taxes.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Reserve Reports will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2014
FORECAST PRICES AND COSTS

CANADA OIL AND GAS ASSETS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	41.6	52.0	-	-	-	16.2	-	0.2
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
TOTAL PROVED	41.6	52.0	-	-	-	16.2	-	0.2
PROBABLE	-	-	-	-	-	-	-	-
TOTAL PROVED PLUS PROBABLE	41.6	52.0	-	-	-	16.2	-	0.2

UNITED STATES OIL AND GAS ASSETS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								-
Developed Producing	1,682.6	1,302.1	-	-	1,677.8	1,298.1	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	3,989.3	3,172.2	-	-	3,888.8	3,090.0	-	-
TOTAL PROVED	5,671.9	4,474.3	-	-	5,566.6	4,388.1	-	-
PROBABLE	3,191.3	2,514.3	-	-	2,813.6	2,217.8	-	-
TOTAL PROVED PLUS PROBABLE	8,863.2	6,988.6	-	-	8,380.2	6,605.9	-	-

AGGREGATED CANADA AND UNITED STATES OIL & GAS ASSETS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	1,724.2	1,354.1	-	-	1,677.8	1,314.3	-	0.2
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	3,989.3	3,172.2	-	-	3,888.8	3,090.0	-	-
TOTAL PROVED	5,713.5	4,526.3	-	-	5,566.6	4,404.3	-	0.2
PROBABLE	3,191.3	2,514.3	-	-	2,813.6	2,217.8	-	-
TOTAL PROVED PLUS PROBABLE	8,904.8	7,040.6	-	-	8,380.2	6,622.1	-	0.2

NET PRESENT VALUE OF FUTURE NET REVENUE – CANADA OIL & GAS ASSETS

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year $/Boe [1]
PROVED:						
Developed Producing	3,357.6	2,433.5	1,871.2	1,505.4	1,253.1	34.09
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	3,357.6	2,433.5	1,871.2	1,505.4	1,253.1	34.09
PROBABLE	-	-	-	-	-	-
TOTAL PROVED PLUS PROBABLE	3,357.6	2,433.5	1,871.2	1,505.4	1,253.1	34.09

Note:
(1) Unit values are based on net volumes.

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	3,321.0	2,415.9	1,862.5	1,500.9	1,250.7
Developed Non-Producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
TOTAL PROVED	3,321.0	2,415.9	1,862.5	1,500.9	1,250.7
PROBABLE	-	-	-	-	-
TOTAL PROVED PLUS PROBABLE	3,321.0	2,415.9	1,862.5	1,500.9	1,250.7

NET PRESENT VALUE OF FUTURE NET REVENUE – UNITED STATES OIL & GAS ASSETS

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% ($US000s)	5% ($US000s)	10% ($US000s)	15% ($US000s)	20% ($US000s)	Unit Value Before Income Tax Discounted at 10% per Year $US/Boe [1]
PROVED:						
Developed Producing	76,593.0	55,964.3	44,538.8	37,442.0	32,639.0	29.33
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	149,021.2	89,000.6	57,581.3	39,049.3	27,149.5	15.62
TOTAL PROVED	225,614.2	144,964.9	102,120.1	76,491.3	59,788.5	19.62
PROBABLE	109,575.4	63,999.6	39,919.7	25,726.7	16,676.7	13.84
TOTAL PROVED PLUS PROBABLE	335,189.6	208,964.5	142,039.8	102,218.0	76,465.2	17.56

Note:
(1) Unit values are based on net volumes.

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($US000s)	5% ($US000s)	10% ($US000s)	15% ($US000s)	20% ($US000s)
PROVED:					
Developed Producing	48,253.6	35,257.6	28,059.4	23,588.5	20,562.6
Developed Non-Producing	-	-	-	-	-
Undeveloped	93,883.4	56,070.4	36,276.2	24,601.1	17,104.2
TOTAL PROVED	142,136.9	91,327.9	64,335.7	48,189.5	37,666.8
PROBABLE	69,032.5	40,319.7	25,149.4	16,207.8	10,506.3
TOTAL PROVED PLUS PROBABLE	211,169.4	131,647.6	89,485.1	64,397.3	48,173.1

NET PRESENT VALUE OF FUTURE NET REVENUE – AGGREGATED CANADA AND UNITED STATES OIL & GAS ASSETS

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year $/Boe (1)
PROVED:						
Developed Producing	92,213.1	67,357.6	53,540.6	44,941.9	39,117.6	34.03
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	172,879.5	103,249.6	66,800.1	45,301.1	31,496.1	18.12
TOTAL PROVED	265,092.6	170,607.2	120,340.7	90,243.0	70,613.7	22.88
PROBABLE	127,118.4	74,246.0	46,310.8	29,845.5	19,346.6	16.06
TOTAL PROVED PLUS PROBABLE	392,211.0	244,853.2	166,651.5	120,088.5	89,960.3	20.46

Note:
(1) Unit values are based on net volumes.

	AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	59,300.0	43,318.1	34,414.3	28,865.9	25,105.3
Developed Non-Producing	-	-	-	-	-
Undeveloped	108,914.1	65,047.2	42,084.0	28,539.7	19,842.6
TOTAL PROVED	168,214.1	108,365.3	76,498.3	57,405.6	44,947.9
PROBABLE	80,084.6	46,774.9	29,175.8	18,802.7	12,188.4
TOTAL PROVED PLUS PROBABLE	248,298.7	155,140.2	105,674.1	76,208.3	57,136.3

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2014
FORECAST PRICES AND COSTS (1)(2)

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
CANADA OIL & GAS ASSETS								
Total Proved	6,089.4	635.2	1,971.3	-	125.3	3,357.6	36.6	3,321.0
Total Proved plus Probable	6,089.4	635.2	1,971.3	-	125.3	3,357.6	36.6	3,321.0
UNITED STATES OIL & GAS ASSETS (3)								
Total Proved	526,431.5	155,910.1	78,853.0	64,378.8	1,675.4	225,614.2	83,477.2	142,136.9
Total Proved plus Probable	826,222.0	245,186.7	122,510.6	120,823.2	2,512.0	335,189.6	124,020.2	211,169.4
AGGREGATED CANADA AND UNITED STATES OIL & GAS ASSETS								
Total Proved	616,802.5	181,506.5	93,448.7	74,685.8	2,069.0	265,092.6	96,878.6	168,214.1
Total Proved plus Probable	964,589.4	285,076.3	144,095.8	140,166.9	3,039.5	392,211.0	143,912.4	248,298.6

Notes:
(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.
(3) Information with respect to the Unites States oil & gas assets is in $US.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2014
FORECAST PRICES AND COSTS

CANADA OIL & GAS ASSETS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1] ($/Bbl)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	1,871.2	34.1
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	1,871.2	34.1
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	1,871.2	34.1
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	1,871.2	34.1

Note:
(1) Unit values are based on gross reserve volumes.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

UNITED STATES OIL & GAS ASSETS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($US000s)	UNIT VALUE [1] ($US/Bbl)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	102,120.1	15.5
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	102,120.1	15.5
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	142,039.8	13.8
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	142,039.8	13.8

Note:
(1) Unit values are based on gross reserve volumes.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

AGGREGATED CANADA AND UNITED STATES OIL & GAS ASSETS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1] ($/Bbl)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	120,340.7	18.1
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	120,340.7	18.1
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	166,651.6	16.2
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	166,651.6	16.2

Note:
(1) Unit values are based on gross reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**Gross**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. "**Net**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

   Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions (see the discussion of "Economic Assumptions" below).

Reserves are classified according to the degree of certainty associated with the estimates.

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"**Economic Assumptions**" are the forecast prices and costs used in the estimate.

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

  (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

  (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. "**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

5. "**Development costs**" means costs incurred to obtain access to our reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from our reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

6. "**Development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

7. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

8. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

9. "**Forecast Prices and Costs**"

   These are prices and costs that are:

   (a) generally acceptable as being a reasonable outlook of the future; and

   (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented in the tables above do not represent fair market value.

12. We do not have any synthetic oil or other products from non-conventional oil and gas activities.

Pricing Assumptions

The forecast cost and price assumptions in this statement assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the NSAI Report were as follows:

SUMMARY OF PRICING AND RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (1)

	GAS US HENRY HUB PRICE ($US/MMBtu)					OIL WTI CRUDE OIL ($US/Bbl)					
Year	**McDaniel & Associates Consultants Ltd.**	**GLJ Petroleum Consultants**	**Sproule Worldwide Petroleum Consultants**	**Deloitte Resource Evaluation & Advisory**	**NSAI Average**	**McDaniel & Associates Consultants Ltd.**	**GLJ Petroleum Consultants**	**Sproule Worldwide Petroleum Consultants**	**Deloitte Resource Evaluation & Advisory**	**NSAI Average**	**EXCHANGE RATE ($US/Cdn) (3)**
Forecast											
2015	3.30	3.31	3.25	3.70	3.39	65.00	62.50	65.00	67.00	64.88	0.84
2016	3.80	3.75	3.75	4.00	3.83	75.00	75.00	80.00	71.40	75.35	0.85
2017	4.05	4.00	4.00	4.25	4.08	80.00	80.00	90.00	74.90	81.23	0.87
2018	4.30	4.25	4.50	4.50	4.39	84.90	85.00	91.35	78.55	84.95	0.87
2019	4.55	4.50	5.00	4.75	4.70	89.30	90.00	92.72	82.25	88.57	0.87
2020	4.85	4.75	5.08	5.00	4.92	93.80	95.00	94.11	86.10	92.25	0.87
2021	5.10	5.00	5.15	5.30	5.14	95.70	98.54	95.52	90.10	94.97	0.87
2022	5.30	5.25	5.23	5.50	5.32	97.60	100.51	96.96	91.90	96.74	0.87
2023	5.50	5.50	5.31	5.80	5.53	99.60	102.52	98.41	93.75	98.57	0.87
2024	5.70	5.68	5.39	6.00	5.69	101.60	104.57	99.89	95.60	100.41	0.87
2025	5.80	5.79	5.47	6.15	5.80	103.60	106.66	101.38	97.50	102.29	0.87
2026	5.90	5.91	5.55	6.40	5.94	105.70	108.79	102.91	99.45	104.21	0.87
2027	6.05	6.03	5.63	6.65	6.09	107.80	110.97	104.45	101.45	106.17	0.87
2028	6.15	6.15	5.72	6.80	6.20	110.00	113.19	106.02	103.50	108.18	0.87
2029	6.30	6.27	5.80	6.95	6.33	112.20	115.45	107.61	105.55	110.20	0.87
Thereafter											
	2%/year	2%/year	1.5%/year	2%/year	2%/year	2%/year	2%/year	1.5%/year	2%/year	2%/year	

Notes:
(1) As at January 1, 2015.
(2) Inflation rate for costs used is 1.88% per year
(3) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us in the United States for the period ended December 31, 2014, excluding price risk management activities, were $US 7.00/Mcf for natural gas and $US 75.25/Bbl for light and medium crude oil.

The forecast cost and price assumptions in this statement assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the McIntosh Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (1)

	NATURAL GAS		CRUDE OIL			NATURAL GAS LIQUIDS		
Year	**Average NYMEX H Hub ($US/MMBtu)**	**PetroShale Price ($Cdn/MMBtu)**	**Average NYMEX WTI ($US/Bbl)**	**Average Edmonton Par ($Cdn/Bbl)**	**PetroShale Oil Price ($Cdn/Bbl)**	**PetroShale NGL Price**	**INFLATION RATES %/Year(2)**	**EXCHANGE RATE ($US/$Cdn)(3)**
Forecast								
2015	3.44	4.45	61.71	65.50	71.02	31.78	2.00	0.845
2016	3.89	4.91	76.25	83.17	88.70	49.46	2.00	0.861
2017	4.14	5.18	82.50	89.66	95.18	55.94	2.00	0.866
2018	4.45	5.56	86.56	94.30	99.82	60.58	2.00	0.866
2019	4.76	5.94	90.51	98.77	104.29	65.05	2.00	0.866
2020	4.98	6.20	94.48	103.54	109.06	69.82	2.00	0.866
2021	5.19	6.45	96.67	105.82	111.35	72.11	2.00	0.866
2022	5.35	6.64	98.48	107.80	113.32	74.08	2.00	0.866
2023	5.49	6.81	100.34	109.82	115.35	76.11	2.00	0.866
2024	5.61	6.97	102.22	111.90	117.43	78.19	2.00	0.866
2025	5.71	7.09	104.13	113.98	119.51	80.27	2.00	0.866
2026	5.82	7.21	106.10	116.12	121.64	82.40	2.00	0.866
2027	5.94	7.36	108.09	118.31	123.84	84.59	2.00	0.866
2028	6.04	7.48	110.13	120.53	126.06	86.82	2.00	0.866
2029	6.16	7.63	112.20	122.80	128.33	89.09	2.00	0.866

Notes:
(1) As at January 1, 2015.
(2) Inflation rate for costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Reserves Reconciliation – Canada

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL		
	Gross Proved (Mbbls)	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**
December 31, 2013	45.6	-	45.6
Discoveries	-	-	-
Extensions/Improved Recovery	1.7	-	1.7
Technical Revisions	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	(0.1)	-	(0.1)
Production	(5.6)	-	(5.6)
December 31, 2014	41.6	-	41.6

Note:
(1) In Canada we have no gross heavy oil, associated and non-associated gas or natural gas liquids. See "*Disclosure of Reserves Data – Reserves Data (Forecast Prices and Costs)*" provided earlier in this statement.

Reserves Reconciliation – United States

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			ASSOCIATED AND NON-ASSOCIATED GAS[1]		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December 31, 2013	432.6	123.2	555.8	448.5	149.6	598.1
Discoveries	-	-	-	-	-	-
Extensions/Improved Recovery	45.2	16.3	61.5	50.8	25.8	76.6
Technical Revisions	166.5	(88.6)	77.9	74.9	(107.4)	(32.5)
Acquisitions	5,137.8	3,146.7	8,284.5	5,030.8	2,750.2	7,781.0
Dispositions	-	-	-	-	-	-
Economic Factors	(9.9)	(6.3)	(16.2)	(6.3)	(4.6)	(10.9)
Production	(100.4)	-	(100.4)	(32.1)	-	(32.1)
December 31, 2014	5,671.9	3,191.3	8,863.2	5,566.6	2,813.6	8,380.2

Notes:

(1) Includes solution gas volumes.

(2) There are no heavy oil or natural gas liquids reserves to be reconciled.

Reserves Reconciliation – Aggregate

	TOTAL CANADA (MBOE)			TOTAL UNITED STATES (MBOE)		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
December 31, 2013	45.6	-	45.6	507.4	148.2	655.5
Discoveries	-	-	-	-	-	-
Extensions/Improved Recovery	1.7	-	1.7	53.7	20.6	74.3
Technical Revisions	-	-	-	179.0	(106.5)	72.5
Acquisitions	-	-	-	5,976.3	3,605.1	9,581.3
Dispositions	-	-	-	-	-	-
Economic Factors	(0.1)	-	(0.1)	(11.0)	(7.1)	(18.0)
Production	(5.6)	-	(5.6)	(105.8)	-	(105.8)
December 31, 2014	41.6	-	41.6	6,599.7	3,660.2	10,259.9

	TOTAL (MBOE)		
	Gross Proved	Gross Probable	Gross Proved Plus Probable
December 31, 2013	553.0	148.2	701.2
Discoveries	-	-	-
Extensions/Improved Recovery	55.4	20.6	76.0
Technical Revisions	179.0	(106.5)	72.5
Acquisitions	5,976.3	3,605.1	9,581.3
Dispositions	-	-	-
Economic Factors	(11.1)	(7.1)	(18.1)
Production	(111.4)	-	(111.4)
December 31, 2014	6,641.3	3,660.2	10,301.5

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by NSAI and McIntosh in the Reserve Reports in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. 100% of our proved undeveloped reserves are in our core areas where we are actively spending capital to develop those properties. As such, we expect that the large majority of our booked undeveloped projects will be completed within a two year time frame. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; (v) changes to development plans of the operators of our properties; and (vi) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of gross proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	**Light and Medium Oil (Mbbls)**		**Heavy Oil (Mbbls)**		**Natural Gas (MMcf)**		**NGLs (Mbbls)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	-	-	-	-	-	-	-	-
June 30, 2013	24.6	24.6	-	-	22.8	22.8	-	-
December 31, 2013	103.6	128.2	-	-	135.3	158.1	-	-
December 31, 2014	3,861.1	3,989.3	-	-	3,730.7	3,888.8	-	-

The majority of our proved undeveloped reserves evaluated in the NSAI Report are attributable to our core properties in North Dakota. Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. NSAI has assigned 4,637.5 Mboe of proved undeveloped reserves with respect to our United States oil and gas assets in the NSAI Report with $US64.4 million of associated undiscounted capital, all of which is forecast to be spent in the first 3 years.

No proved undeveloped reserves were attributed by McIntosh with respect to our Canadian oil and gas assets.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of gross probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	**Light and Medium Oil (Mbbls)**		**Heavy Oil (Mbbls)**		**Natural Gas (MMcf)**		**NGLs (Mbbls)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	-	-	-	-	-	-	-	-
June 30, 2013	18.3	18.3	-	-	20.2	20.2	-	-
December 31, 2013	105.0	123.2	-	-	129.4	149.6	-	-
December 31, 2014	3,068.1	3,191.3	-	-	2,664.0	2,813.6	-	-

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. NSAI has assigned 3,660.2 Mboe of probable undeveloped reserves with respect to our United States oil and gas assets in the NSAI Report with $US56.4 million of associated undiscounted capital all of which is forecast to be spent in the first 3 years.

No probable undeveloped reserves were attributed by McIntosh with respect to our Canadian oil and gas assets.

Significant Factors or Uncertainties

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

	FORECAST PRICES AND COSTS CANADA		**FORECAST PRICES AND COSTS UNITED STATES**	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**	**Proved Reserves ($US000s)**	**Proved Plus Probable Reserves ($US000s)**
2015	-	-	5,542.4	5,868.0
2016	-	-	35,443.2	82,028.6
2017	-	-	23,393.1	32,926.6
2018	-	-	-	-
2019	-	-	-	-
Remaining	-	-	-	-
Total (Undiscounted)	-	-	64,378.8	120,823.2

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the NSAI Report. Failure to develop those reserves could have a negative impact on our future cash flow.

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic.

Other Oil and Natural Gas Information

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2014. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

United States

Mondak Project

Our Mondak project is located in Richland County, Montana and McKenzie County, North Dakota. The Mondak project was assembled based upon five un-stimulated horizontal wells that the operator drilled adjacent to or within the Mondak area in 1992 and 2007. Our primary target of the Mondak properties when it was acquired was the

Upper Bakken Shale. There have been eleven wells drilled within this area to test the continuity of the shale resource across the acreage and to test completion techniques in the shale. The future plans for the Mondak project include a sale or a partial sell-down. All or parts of the future plans are expected to occur over the next 24 months. We had approximately 20 Bbls/d of production in the quarter ending December 31, 2014. As at December 31, 2014, we impaired the remaining costs associated with this area included in Exploration and Evaluation assets.

The following are our North Dakota core areas:

Melbby Project

Our Melbby project is located in Mountrail County, North Dakota. We hold a 1.3% average working interest in 48 producing wells located in the Alger, Big Bend, Clear Water, Kittleson Slough, Parshall, Ross, Sanish, and Van Hook fields. Production from the project is approximately 91% oil weighted, and the majority of the wells are operated by Slawson. We did not participate in any wells on this project during the year ended December 31, 2014. During this period, production from this project averaged approximately 30 Boe/d net to us.

MJ Angus Project

Our MJ Angus Project is located in the Antelope area of North Dakota. We hold 105 net acres of land and a 1.5% average working interest in eleven producing wells in the middle Bakken and Three Forks play. Further, there is potential for future increased density well locations in two producing 53 net acre drilling units. In addition, in this area we own 52 net acres in six undeveloped drilling units. We did not participate in any wells during the year ended December 31, 2014. During this period, production from this project averaged approximately 60 Boe/d net to us.

Stockyard Project

We hold approximately 106 acres in the Stockyard Creek Field, Southern Williams County, North Dakota with an approximate 5.5% working interest in a 17 well continuous drilling program over three 640 acre sections; and (ii) a 5.0% interest in a drilled middle Bakken well which was being completed at the time of the acquisition. Slawson is the operator of this project.

To date, five wells have been successfully completed in Stockyard and each is currently producing at gross rates of between 300 Bbls/d and 800 Bbls/d of light, sweet crude oil. Currently, production net to us from this project is approximately 200 Boe/d.

Antelope Project

In January of 2014 we acquired additional assets in the Antelope area of North Dakota. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Changes to Reserves Data – Acquired Assets*" in this Annual Information Form. The operator of this property has commenced drilling a single well on this property which we anticipate will begin production in the second quarter of 2015.

North Nesson Project

Through a series of acquisitions in February and June of 2014 we acquired additional assets in the North Nesson area of North Dakota. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Changes to Reserves Data – Acquired Assets*" in this Annual Information Form. The operator of this property has drilled and completed six wells to date on this property which we expect will commence production in the second quarter of 2015.

Canada

Southern Ontario

Our producing oil and gas assets evaluated in the McIntosh Report consist of working interests in an existing Ordovician unit and a multi-legged Ordovician oil well in south-western Ontario, plus various overriding royalty interests in a number of non-operated horizontal multi-legged Ordovician oil wells. We own a 100% working interest in the Colchester South Ordovician Pool unit located in Colchester South Township, Essex County, and 100% working interest in Colchester South 18, a multi-lateral horizontal Ordovician oil well extending under Lake Erie. As well as this ownership interest, we receive an overriding royalty interest in a number of horizontal Ordovician oil wells located in Romney Township, Kent County, Ontario.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2014.

	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada	3.0	3.0	3.0	3.0	-	-	-	-
Montana	9.0	0.8	-	-	-	-	-	-
North Dakota	146.0	4.4	34.0	2.1	-	-	-	-
Total	158.0	8.2	38.0	6.1	-	-	-	-

Of the non-producing wells, 27 gross (0.8 net) were drilled in 2014 that were capable of production and had reserves assigned to them.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2014.

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES	
	Gross	Net	Gross	Net	Gross	Net
Canada	-	-	242	242	242	242
Montana	26,379	647	10,077	789	36,456	1,436
North Dakota	31,641	1,502	34,059	1,470	65,700	2,972
Total	58,020	2,149	44,378	2,501	102,397	4,650

Rights to explore, develop and exploit 94 net acres of these undeveloped land holdings have expired since December 31, 2014 and a further 495 net acres could expire by December 31, 2015 if not continued.

When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us from time to time to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by contracting with a large, multi-national energy company.

We may use certain financial instruments to hedge exposure to commodity price fluctuations on a portion of our crude oil and natural gas production. For further information, see note 11 to our financial statements for the year ended December 31, 2014. See "*Risk Factors – Hedging*".

Additional Information Concerning Abandonment and Reclamation Costs

Our overall abandonment and reclamation costs are based on well bore abandonment and reclamation costs and liability issues such as flare pit remediation, facility decommissioning, remediation and reclamation costs. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing well bores for reactivation, recompletion or sale and conduct systematic abandonment programs for those well bores that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs.

As at December 31, 2014 we had 181 gross (10.8 net) wells for which we expect to incur abandonment and reclamation costs.

The total amount of abandonment and reclamation costs that we expect to incur, as reflected in the Reserve Reports, net of estimated salvage values, are summarized in the following table:

Period	Abandonment and Reclamation Costs Escalated at 1.7% to 2% Undiscounted ($000s)		Abandonment and Reclamation Costs Escalated at 1.7% to 2% Discounted at 10% ($000s)	
	Canada	United States (1)	Canada	United States (1)
Total liability as at December 31, 2014	125.3	2,512.0	54.3	176.6
Anticipated to be paid in 2015	-	1.0	-	0.9
Anticipated to be paid in 2016	-	-	-	-
Anticipated to be paid in 2017	-	17.5	-	13.8

Note:
(1) Values for our United States assets are in $US.

Tax Horizon

Based on our recent developments and estimated pro-forma 2015 cash flow and capital expenditures, we do not expect to be cash taxable in 2015. See "*General Development of our Business – Recent Developments*."

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2014.

Expenditure	Canada ($000s)	United States ($US000s)
Property acquisition costs – Unproved properties (1)	-	73
Property acquisition costs – Proved properties (2)	-	32,808
Corporate acquisition costs	-	-
Exploration costs (3)	-	50
Development costs (4)(5)	-	24,948
Other	-	27
Total	-	57,906

Notes:
(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Net of dispositions.
(3) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
(5) Net of drilling credits.

Exploration and Development Activities

The following table sets forth the gross development wells in which we participated during the year ended December 31, 2014. We participated in one exploratory well during the year, which was a dry hole.

	Wells - Canada		Wells - United States	
	Gross	Net	Gross	Net
Natural Gas	-	-	-	-
Light and Medium Oil	-	-	43	3.3
Dry	-	-	-	-
Total	-	-	43	3.3

In 2015, we expect to participate in the drilling of approximately 34 (2.2 net) oil wells in North Dakota. We do not expect to drill any wells in Montana or Ontario.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2015, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data*".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (Boe/d)
Total Proved					
Canada	21.2	-	5.0	0.1	22.1
Montana	12.7	-	1.8	-	13.0
North Dakota	1,168.8	-	1,156.2	-	1,361.5
Total	1,202.6	-	1,163.0	0.1	1,396.5
Total Proved plus Probable					
Canada	21.2	-	5.0	0.1	22.1
Montana	12.7	-	1.8	-	13.0
North Dakota	1,173.1	-	1,162.1	-	1,366.8
Total	1,207.0	-	1,168.9	0.1	1,401.9

Production History

The following tables summarize certain information in respect of our production, product prices received, royalties paid, production taxes and transport, production costs and resulting netback for the year ended December 31, 2014:

Canada Production

	Quarter Ended 2014			
	March 31	June 30	September 30	December 31
Average Daily Production				
Light and Medium Oil (bbls/d)	14	24	17	25
Natural Gas Liquids (bbls/d)	-	-	-	-
Gas (Mcf/d)	3	4	4	4
Combined (boe/d)	15	25	18	26
Average Net Production Prices Received				
Light and Medium Oil ($/bbl)	101.99	108.98	103.43	76.76
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	10.48	6.78	2.98	3.2
Royalties Paid				
Light and Medium Oil ($/bbl)	10.41	11.51	7.97	4.18
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	-	-	-	-

	Quarter Ended 2014			
	March 31	June 30	September 30	December 31
Production Costs [(1)]				
Light and Medium Oil ($/bbl)	34.94	40.28	45.34	38.42
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	-	-	-	-
Netback Received				
Light and Medium Oil ($/bbl)	56.64	57.19	50.12	34.16
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	10.48	6.78	2.98	3.20

Note:

(1) All of our natural gas production is gas associated with our oil production. As such we are not able to break out the production costs for product type.

United States Production

	Quarter Ended 2014			
	March 31	June 30	September 30	December 31
Average Daily Production				
Light and Medium Oil (bbls/d)	145	259	223	464
Natural Gas Liquids (bbls/d)	-	-	-	-
Gas (Mcf/d)	40	85	44	175
Combined (boe/d)	152	273	230	493
Average Net Production Prices Received				
Light and Medium Oil ($/bbl)	93.11	100.34	92.56	66.13
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	9.56	9.46	5.46	6.97
Royalties Paid				
Light and Medium Oil ($/bbl)	23.55	23.29	20.60	14.82
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	2.40	2.11	1.47	1.55
Production Taxes & Transport [(1)]				
Light and Medium Oil ($/bbl)	5.81	7.78	8.01	5.05
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	0.06	0.06	0.06	0.06
Production Costs [(1)]				
Light and Medium Oil ($/bbl)	8.66	9.49	8.36	6.59
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	-	-	-	-
Netback Received				
Light and Medium Oil ($/bbl)	55.09	59.78	55.59	39.67
Natural Gas Liquids ($/bbl)	-	-	-	-
Gas ($/Mcf)	7.10	7.29	3.93	5.36

Note:

(1) All of our natural gas production is gas associated with our oil production. As such we are not able to break out the production costs for product type.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2014.

	Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Natural Gas (Mcf/d)	BOE (Boe/d)
Canada	20	-	4	21
Montana	21	-	-	21
North Dakota	253	-	86	268
Total	294	-	90	309

DESCRIPTION OF OUR CAPITAL STRUCTURE

Share Capital

Common Shares

The holders of Common Shares are entitled to: dividends if, as and when declared by the Board of Directors; to one vote per Common Share at meetings of the holders of our Common Shares; and upon liquidation, dissolution or winding up of the Corporation to receive pro rata the remaining property and assets of the Corporation. The Common Shares shall not be subdivided, consolidated, reclassified or otherwise adjusted unless, contemporaneously therewith, the Common Non-Voting Shares are subdivided, consolidated, reclassified or otherwise adjusted in the same proportion and in the same manner. As of the date hereof there are 27,707,574 Common Shares issued and outstanding.

Common Non-Voting Shares

The holders of Common Non-Voting Shares are entitled to: dividends if, as and when declared by our Board of Directors provided that no dividend may be declared unless concurrently therewith the same dividend is conferred upon the holders of our Common Shares; and upon liquidation, dissolution or winding up of the Corporation to receive pro rata the remaining property and assets of the Corporation. A holder of Common Non-Voting shares shall have the right to convert all or some of the Common Non-Voting Shares into Common Shares on a one-for-one basis at any time, however the holder cannot convert the Common Non-Voting Shares if it would result in the holder beneficially owning or exercising control or direction of ten percent or more of our Common Shares at any time. The Common Non-Voting Shares shall not be subdivided, consolidated, reclassified or otherwise adjusted unless, contemporaneously therewith, the Common Shares are subdivided, consolidated, reclassified or otherwise adjusted in the same proportion and in the same manner. If an offer to acquire is made, the holders of the Common Non-Voting Shares shall not be entitled to accept such offer until the offeror has made the offer to all of the holders of the Common Shares on the same terms and conditions as the offer was made to the holders of the Common Non-Voting shares. As of the date hereof there are 6,499,978 Common Non-Voting Shares issued and outstanding. All of the Common Non-Voting Shares are beneficially held by Alameda.

Preferred Shares

Our Board of Directors may fix the designation, rights, privileges, restrictions and conditions attached to each series of our Preferred Shares prior to them being issued. In the event of liquidation, dissolution or winding-up of the Corporation, holders of each series of Preferred Shares shall be entitled to be paid in priority to holders of Common Shares and Common Non-Voting Shares on a distribution of the capital of the Corporation. As of the date hereof there are no Preferred Shares outstanding.

Credit Facilities

We currently have a senior secured revolving line of credit with a Canadian financial institution. The senior credit facility has an initial borrowing base of US$10 million and is guaranteed by GEL, PetroShale and PetroShale US. This borrowing base was increased on March 25, 2015 to US$15.5 million. Our Senior Credit Facility is a demand loan with a renewal date of March 24, 2016. At this point, the bank has the option to extend the term or convert the loan into a non-revolving term facility.

We also have a $50 million revolving acquisition facility provided by our two largest shareholders, Mr. M. Bruce Chernoff and Mr. Todd Slawson. The acquisition facility bears interest at 12% per annum, has a commitment fee of 2.5%, and is secured by all of the Canadian and US assets of PetroShale, subject to subordination to our senior credit facility discussed above. This facility has a maturity date of December 31, 2016. See "*Interest of Management and Others in Material Transactions*".

MARKET FOR OUR SECURITIES

Trading Price and Volume

Our Common Shares trade on the TSX Venture Exchange under the symbol "PSH". The following sets out the high and low trading prices and aggregate volume of trading of our Common Shares on the TSX Venture Exchange for the periods noted below:

Period	High ($)	Low ($)	Volume
2014			
January	1.40	1.27	384,844
February	1.40	1.26	146,730
March	1.40	1.29	1,206,420
April	1.40	1.31	189,883
May	1.50	1.24	201,810
June	1.40	1.30	493,328
July	1.68	1.38	773,302
August	1.75	1.57	532,554
September	3.00	1.57	232,083
October	2.85	1.79	243,822
November	2.15	1.67	357,524
December	2.04	0.93	450,660
2015			
January	1.30	1.07	21,098
February	1.25	0.98	23,256
March (to March 27)	1.23	1.12	5,410

Prior Sales

During the year ended December 31, 2014, we issued 275,000 options to acquire Common Shares pursuant to our stock option plan at a weighted average exercise price of $1.40 per Common Share. No funds are received by us until such time as the option is exercised.

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below.

Name and Municipality of Residence	Position with PetroShale	Director Since	Principal Occupation
M. Bruce Chernoff (2)(3) Calgary, Alberta, Canada	Executive Chairman, Chief Executive Officer and Director	August 31, 2012	Our Executive Chairman and Chief Executive Officer; President of Caribou Capital Corp., a private investment company, since 1999.
James D. Fair Gross Pointe, Michigan, USA	Director	March 8, 2012	Independent businessman. During the period of October 31, 2013 to November 25, 2013, Mr. Fair was our Interim Chief Executive Officer and Interim President.
Brett Herman (1)(3) Calgary, Alberta, Canada	Director	March 8, 2012	President and Chief Executive Officer of TORC Oil & Gas Ltd., a public oil and gas company.
Ken McCagherty (1)(2) Calgary, Alberta, Canada	Director	November 25, 2013	President and Chief Executive Officer of Westbrick Energy Ltd., a private oil and gas company since October 2010.
Jacob Roorda (1)(2)(3) Calgary, Alberta, Canada	Director	March 8, 2012	Managing director of Windward Capital Limited, a private investment company. Chief Executive Officer of Todd Corporation, a private oil and gas company since January 2015. Vice Chairman of Canoe Financial Corp., a private investment management company, from May 2010 to October 2011.
John Fair Denver, Colorado, USA	President of PetroShale US	N/A	Mr. Fair is the President of our US subsidiary PetroShale US.
David Rain Calgary, Alberta, Canada	Chief Financial Officer	N/A	Our Chief Financial Officer since November 2013 and the Chief Financial Officer and Vice President of Caribou Capital Corp. since 1999.
Antonio Izzo Calgary, Alberta, Canada	Vice President, Business Development	N/A	Our Vice President, Business Development and Vice President, Business Development of Caribou Capital Corp since November 2013. Prior thereto Mr. Izzo was the Vice President, Engineering with Canoe Financial Corp.

Notes:
(1) Member of our Audit Committee.
(2) Member of our Reserves Committee.
(3) Member of our Corporate Governance and Compensation Committee.

The term of office of each of our directors expires at the next annual meeting of our Shareholders.

As at the date of this Annual Information Form, our directors and executive officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 14,705,417 Common Shares or approximately 53.5% of our issued and outstanding Common Shares and no Common Non-Voting Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

None of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer other than Mr. Roorda who was formerly a director of Argosy Energy Inc. when it was cease traded for failure to file financials in April of 2012.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets other than the following. Mr. Roorda who was formerly a director of TXCO Resources Ltd. which filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the United States Bankruptcy Court for the Western District of Texas on April 18, 2009 and formerly a director of Argosy Energy Inc. when it entered receivership pursuant to an order of the Court of Queen's Bench of Alberta on May 30, 2013 at the request of its lenders. Mr. Chernoff and Mr. Rain were each formerly directors of Calmena Energy Services Inc. (a public oilfield service company) which was placed in receivership on January 20, 2015. Mr. Chernoff and Mr. Rain resigned as directors of Calmena effective January 15, 2015.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*". Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such board members will be provided to us.

The *Business Corporations Act* (Alberta) provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the *Business Corporations Act* (Alberta). To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

The charter of our audit committee (the "**Audit Committee**") is attached to this annual information form as Appendix "A".

Composition of the Audit Committee

The current members of the Audit Committee are Messrs. Herman, McCagherty and Roorda. Each of the members of the Audit Committee is independent and is financially literate.

Relevant Education and Experience

Mr. Herman is the chairman of our Audit Committee. Mr. Herman's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his professional training as a chartered accountant and over 20 years of experience as either a Chief Financial Officer or President and Chief Executive Officer of various oil and gas firms.

Mr. McCagherty's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his thirty (30) years of experience in the energy industry as President and Chief Executive Officer and as a director of various oil and gas companies, and his training as a Professional Engineer.

Mr. Roorda's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his thirty-two (32) years of experience in the energy and financial services industry. Mr. Roorda has been a director and officer of several public companies and was the Managing Director of investment banking at Research Capital Corp. Mr. Roorda is a Professional Engineer and has a MBA from the University of Calgary.

Reliance on Certain Exemptions

At no time since the commencement of our most recently completed financial year has the Corporation relied on the exemption in Section 2.4 of Multilateral Instrument 52-110 – *Audit Committees* ("**MI 52-110**") (De Minimis Non-audit Services), or an exemption from MI 52-110, in whole or in part, granted under Part 8 of MI 52-110.

Audit Committee Oversight

At no time since the commencement of our most recently completed financial year was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the board of directors of the Corporation.

Pre-Approval Policies and Procedures

The Audit Committee must pre-approve all non-audit services to be provided to the Corporation by the external auditors. The Audit Committee may delegate to one or more members of the board of directors, the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Auditor Service Fees (By Category)

The aggregate fees billed by the Corporation's external auditors in each of the last two fiscal years for audit fees are as follows:

Financial Year Ending	Audit Fees	Audit Related Fees	Tax Fees	All Other Fees
2014	$127,383	-	$31,824	-
2013(1)	$83,653	-	-	-
2013	$71,000	-	$1,000	-

Notes:

(1) The Corporation's financial year end was changed from June 30 to December 31 on February 11, 2014. The amounts disclosed are for the six month period ended December 31, 2013.

Exemption

We are relying on the exemption provided in Section 6.1 of MI 52-110 and, as such, we are exempt from Parts 3 (Composition of the Audit Committee) and 5 (Reporting Obligations) of MI 52-110.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Mr. M. Bruce Chernoff, through an entity substantially owned by him, acquired a controlling interest in our Common Shares in connection with the concurrent private placement which closed immediately before the reverse takeover of Algonquin, see: "*General Development of Our Business – History and Development*". Mr. Chernoff was not a member of our Board of Directors during the time of the reverse takeover transaction or the private placement. Currently Mr. Chernoff holds approximately 12.2 million Common Shares, representing 44.3% of our issued and outstanding Common Shares.

Currently, we have a US$50 million revolving acquisition facility provided by entities beneficially owned by Mr. M. Bruce Chernoff and Mr. Todd Slawson. As of the date hereof, Mr. Slawson owns directly or indirectly approximately 10% of our Common Shares and directly or indirectly owns, controls or directs 100% of our Common Non-Voting Shares.

DIVIDEND POLICY

We have not declared or paid any dividends on our Common Shares or Non-Voting Common Shares. Any decision to pay dividends on the Common Shares will be made by our Board of Directors on the basis of our earnings, financial requirements and other conditions that the Board of Directors may consider appropriate in the circumstances. It is not intended that dividends will be paid in the foreseeable future.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Ontario, the United States, Montana and North Dakota, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Our wholly-owned subsidiary, PetroShale US, holds interests in oil and natural gas properties and related assets in Montana and North Dakota in the United States and our Canadian subsidiary GEL holds our assets in Ontario in Canada. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in the areas where we operate.

Pricing, Marketing and Transportation

United States

The sales prices of oil, natural gas liquids and natural gas are currently set by the market. However, we cannot predict whether new legislation to regulate the price of energy commodities might be proposed, what proposals, if any, might actually be enacted by the US Congress or the various state legislatures and what effect, if any, such proposals might have on the operations of the underlying properties.

The US Federal Energy Regulatory Commission ("**FERC**") regulates rates and service conditions for the transportation of natural gas in interstate commerce, which affects the marketing of natural gas we produce, as well as the revenues we receive for sales of such production. FERC exercises its ratemaking authority by applying cost-of-service principles, allowing for the negotiation of rates where there is a cost-based alternative rate or the granting of market-based rates in certain circumstances. FERC has also undertaken various initiatives to increase competition in the natural gas industry, which may indirectly affect our business and the markets for products derived from our business. These policies include regulations on open access transportation, natural gas quality, capacity release and market center promotion. We may be also indirectly subject to certain reporting requirements of FERC based on the sale of gas from producing properties in which we have interest.

The prices and terms of access to intrastate pipeline transportation are subject to state regulation. FERC has proposed and implemented new rules and regulations affecting gas transportation in recent years. We do not believe that we will be affected by any such rules or changes to existing rules in a manner materially different than any other similarly situated natural gas producer.

Rates and service conditions for the interstate transportation of oil and natural gas liquids are also regulated by FERC. In general, these rates must be cost-based or based on an indexing system of transportation rates that allows pipelines to take an annual inflation-based rate increase. FERC has also established market-based rates and settlement rates as alternative forms of ratemaking in certain circumstances. We cannot predict with any certainty what effect, if any, these regulations will have, but other factors being equal, the regulations may, over time tend to increase transportation costs which may have the effect of reducing net prices for oil and natural gas liquids.

Natural gas gathering facilities are exempt from regulation by FERC under Section 1(b) of the Natural Gas Act. We believe that pipelines in which we have an interest will meet the "primary function test" that FERC has used to establish a pipeline's status as a gathering system not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission pipelines and unregulated gathering systems has been subject to extensive litigation and is made by FERC on a case-by-case basis. Consequently, the classification and regulation of gathering facilities in which we have an interest may be subject to change based on future determinations by FERC, the courts or US Congress. Such a change may result in increased regulation of such assets and could have an adverse and material effect on our operations, operating expenses and revenues.

Canada

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal Jobs, Growth and Long-term Prosperity Act, which received Royal Assent on June 29,

2012. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the National Energy Board Act.

Natural Gas

Natural gas is traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States. Spot and future prices can be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Land Tenure and Royalties

United States

In the United States, the federal government and each state have statutes and regulations which govern oil and gas lease terms, including tenure, royalties, production rates and other provisions. Oil and gas lessees are often required to pay annual rental payments to comply with federal, state and private lease provisions until production begins or the lease term expires. Upon commencement of production, royalties and production taxes are paid on revenue received from oil and natural gas produced from federal, state and private lands. The royalty and production tax regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than federal and state lands in the US are determined by negotiations between the private mineral owner and the lessee. Federal, US Indian and state royalties and production taxes in the US are determined by government regulation and are generally calculated as a percentage of the value of the gross production less approved marketing and transportation deductions. The royalty rate payable for federal leases is generally fixed at 12.5% and varies from state to state for leases covering state-owned minerals. State minerals are currently being leased subject to an 18.75% royalty rate in North Dakota and a 16.67% royalty rate in Montana. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalty interests, or net profits interests.

Private mineral ownership in the US is prevalent and generally on lands settled and patented before the early 1900's. The federal government and the state in which the minerals are located also hold ownership to mineral rights. The federal mineral rights are administered by the Bureau of Land Management under the Department of the Interior ("**BLM**"). These owners, from governmental bodies to private individuals, grant rights to explore for and produce oil and gas pursuant to oil and gas leases, providing for varying consideration, term and royalties. As to those rights held by private owners, all terms and conditions may be negotiated. For those rights held by governmental agencies, typically the terms and conditions of the oil and gas lease have been predetermined by each governing or regulatory body and the consideration is determined by oral bidding.

A lease may generally be continued after the primary term provided certain minimum levels of drilling operations or production have been achieved and all lease rentals have been timely paid, subject to certain exceptions. To develop minerals, including oil and gas, it is necessary for the mineral estate owner(s) to have access to the surface estate. Under common law, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each state has developed and adopted their own statutes that operators must follow both prior to drilling and following drilling including notification requirements and to provide compensation for lost land use and surface damages. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

Canada

In Canada, provincial governments predominantly own the rights to crude oil and natural gas. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each province also has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the private mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. In Ontario, the Crown royalty rate for oil and gas is 12.5%, based on monthly production and the full sale price of the oil or gas received at the point of sale. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Environmental Regulation

Canada

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

In Ontario, the exploration, drilling and production of crude oil and natural gas is regulated by the Ministry of Natural Resources (the "**Ministry**") under the Oil, Gas and Salt Resources Act, the Exploration, Drilling and Production Regulation and the Provincial Operating Standards. The Oil, Gas and Salt Resources Act and regulations ensure that the operational activities of the oil and natural gas industry do not pose a threat to public safety or the environment. The Ministry ensures compliance with legislation, regulations and operating standards through licensing, monitoring, inspecting and reporting on drilling and production. The Environmental Protection Act and regulations are the main source of environmental regulation in Ontario and establish the government's environmental objectives for the control of air, water and land pollution.

United States

Our US oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the abandonment of wells. Our US operations are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in a spacing unit and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally restrict the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells. In particular, the NDIC implemented new rules in 2014 mandating a natural gas capture plan and production restrictions to reduce gas flaring associated with oil production.

At the federal level, well planning and permitting is primarily regulated by the BLM and Bureau of Indian Affairs for operations on public and tribal lands under the Federal Land Policy and Management Act and the National Environmental Policy Act ("**NEPA**"). Environmental conservation and cultural and natural resources protection at the federal level are administered by numerous agencies under multiple statutes. The BLM can suspend permit approvals in specific areas while environmental analyses are being conducted and compliance documents required by the NEPA are being prepared (e.g. environmental assessments and environmental impact statements). Environmental planning, permitting and compliance related to media protection and contaminants at the federal level are administered by the US federal Environmental Protection Agency (the "EPA") or by various states whose programs have been granted primacy by the EPA. The EPA governs federal legislation, including the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act (other than oil and gas exempt wastes), the Comprehensive Environmental Response, Compensation, and Liability Act, the Oil Pollution Act, the Emergency Planning and Community Right-to-Know Act, the Safe Drinking Water Act (other than exclusions for underground injection) and Federal Executive Orders. PetroShale US's operations are subject to various regulations, including those relating to well permits, linear facilities, hydraulic fracturing, underground injection and setbacks (buffers) for environmental protection, including a number of state agencies regulating oil and gas activities. In addition to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, state water quality, fish, wildlife, visual quality, transportation, noise, spills, incidents and transportation.

Additional regulations affecting our operations include: the Federal Implementation Plan for Oil and Natural Gas Production Facilities (which requires oil and natural gas owners and operators producing from the Bakken Pool on the Fort Berthold Indian Reservation in North Dakota to reduce emissions of volatile organic compounds) and the new air emission control rules for the oil and natural gas industry (which limit emissions of volatile organic compounds, sulphur dioxide and other air toxics in the oil and gas sector and include the first federal air standards for natural gas wells that are hydraulically fractured).

At the request of US Congress, in 2011, the EPA began research under its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. The purpose of the study is to assess the potential impacts of hydraulic fracturing on drinking water resources, and to identify the driving factors that may affect the severity and frequency of such impacts. The focus is primarily on hydraulic fracturing of shale formations to extract natural gas, with some study of other oil- and gas-producing formations, including tight sands and coalbeds. The results of this study are expected to be released in draft form for public comment and peer review in late 2014, which was recently delayed by the EPA until "early 2015". The BLM, which regulates oil and gas operations located on federal and tribal lands, published its latest proposed hydraulic fracturing rules on May 24, 2013. The BLM reportedly received over 1.5 million public comments in response to the draft and supplemental proposals which helped inform the final rule. On March 20, 2015, the BLM issued its final rule, which imposed more stringent standards on hydraulic fracturing operations. The final rule aims to improve public safety and protect groundwater by updating the requirements for well-bore integrity, wastewater disposal and public disclosure of chemicals during hydraulic fracturing operations.

States also have the authority to regulate hydraulic fracturing. North Dakota and Montana have regulations that require operators to disclose information about the chemicals used in their hydraulic fracturing fluids on the internet-based chemical registry FracFocus. FracFocus is operated by the Ground Water Protection Council, a group of state water officials, and the Interstate Oil and Gas Compact Commission, an association of oil and gas producing states. The online registry was created in 2011, in response, at least in part, to concerns from landowners about the chemical content of fracturing fluids that were being injected into oil and gas wells on their land as well as adjacent properties. FracFocus is widely accepted among the petroleum industry and currently lists over 1,000 companies as registry participants.

Implementation of more stringent environmental regulations could affect the capital and operating expenditures and plans for our operations. We minimize the potential of these impacts to our operations in many ways, including through participation and membership in trade organizations, such as the North Dakota Petroleum Council and focus on drilling near gas pipeline infrastructure.

We believe that, in all material respects, we are in compliance with, and have complied with, all applicable environmental laws and regulations. We have made and will continue to make expenditures in our efforts to comply with all environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with governmental regulations. We believe that our continued compliance with existing requirements has been accounted for and will not have a material and adverse impact on our financial condition, results of operations and operating cash flows. However, we cannot predict the passage of or quantify the potential impact of any more stringent future laws and regulations at this time.

Climate Change Regulation

Canada

The Government of Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of greenhouse gas emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which sets forth a plan for regulations to address both greenhouse gas and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing greenhouse gas emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce greenhouse gas emissions.

United States

On December 15, 2009, the EPA published its final findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and welfare of current and future generations. These findings allow the EPA to adopt and implement regulations that would restrict greenhouse gas emissions under existing provisions of the federal Clean Air Act.

One such regulation establishes greenhouse gas emissions thresholds that determine when stationary industrial sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V Operating Permit programs of the Clean Air Act (the "**Tailoring Rule**"). The permitting requirements of the PSD program apply only to newly-constructed or modified major sources of greenhouse gas emissions. Obtaining a PSD permit requires state and local permitting agencies to ensure that a source adopts the best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Montana and North Dakota are in a position to issue permits consistently with the Tailoring Rule as their existing rules and regulations are consistent with the framework for implementation of the Tailoring Rule provisions.

The Tailoring Rule established a phased in approach to provide time for large industrial facilities and state governments to develop the capacity to implement permitting requirements for greenhouse gas emissions. Phase I of the Tailoring Rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing greenhouse gas emissions by more than 75,000 tons per year to adopt BACT for their greenhouse gas emissions. Phase II of the Tailoring Rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of greenhouse gas emissions per year or existing facilities that make major modifications increasing greenhouse gas emissions by more than 75,000 tons per year. Phase III of the Tailoring Rule, which became effective on August 13, 2012, aims to streamline the permitting process and does not lower the current thresholds for applicability of the PSD and Title V Operating Permit programs. By April 30, 2015, the EPA will complete a study on remaining greenhouse gas permitting burdens that would exist if the PSD and Title V Operating Permit programs were applied to smaller sources. A final rule incorporating the results of this study is expected by April 30, 2016. On June 23, 2014, the Unites States Supreme Court ruled that the EPA cannot treat greenhouse gases as an air pollutant for the purposes of determining whether a source is a major source required to obtain a PSD or title V permit. However, PSD permits that are otherwise required (based on emissions of other pollutants) may continue to require limitations on greenhouse gas emissions based on BACT.

On November 30, 2010, the EPA published a final rule that expands its rule on mandatory reporting of greenhouse gas emissions to include owners and operators of petroleum and natural gas systems with greenhouse gas emissions above certain threshold levels (25,000 tons or more of greenhouse gas emissions per year). Monitoring of those newly covered emissions commenced on January 1, 2011. We do not believe that any of the facilities in which we have an interest are required to report under this rule.

The adoption and implementation of any regulations imposing reporting obligations on, or limiting greenhouse gas emissions from, our operations, and the equipment utilized in those operations, could have a material adverse effect on our results of operations, cash flows and financial condition. Depending on the legislation or regulatory programs that may be adopted to address greenhouse gas emissions, we could be required to incur costs to reduce greenhouse gas emissions resulting from our operations and could be required to purchase and surrender allowances for greenhouse gas emissions associated with our operations or the oil and natural gas we produce. Although we do not anticipate that we would be impacted to a greater degree than other similarly situated producers of oil and natural gas, a stringent greenhouse gas emissions control program could have an adverse effect on our cost of doing business and could reduce demand for the oil and natural gas we produce.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.

Early Stage of Development

An investment in us is subject to certain risks related to its early stage of development. There are numerous factors which may affect our success which are beyond our control including local, national and international economic conditions. Our foreign operations expose us to risks which may not exist for domestic operations such as political and currency risks. We have a limited history of operations. Our business involves a high degree of risk and there can be no assurance that our business will be successful or profitable or that we will discover commercial quantities of crude oil or natural gas.

To become profitable, we would need to be successful in our acquisition, exploration, development and production activities, all of which are subject to many risks beyond our control. We cannot assure we will successfully implement our business plan or that we will achieve commercial profitability in the future. Even if we become profitable, we cannot assure profitability will be sustainable or increase on a periodic basis.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability, and those of the operators of our properties, to find, acquire, develop and commercially produce oil and natural gas reserves. See also "*Operational Dependence*" below. Without the continual addition of new reserves, any existing reserves that we may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in our reserves will depend not only on our ability and the ability of the operators of our properties to explore and develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. No assurance can be given that we will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, we may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that we will discover or acquire any commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. Particularly, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects.

In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event we could incur significant costs.

Operational Dependence

Other companies operate the majority of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices. Such limited control over the amount and timing of capital expenditures incurred on our properties operated by others may create risk for us in terms of our ability to budget and finance such capital expenditures, and could also result in the expiry of our lease interests.

Foreign Subsidiaries

We conduct most of our operations through our subsidiaries and other companies located outside of Canada. The ability of our subsidiaries and other companies to make payments to us may be constrained by among other things: the level of taxation, particularly corporate profits and withholding taxes, in the jurisdiction in which it operates; and the introduction of exchange controls or repatriation restrictions.

Foreign Operations

Our principal interests in oil and natural gas properties are located in the United States. As such, we are subject to political, economic and other uncertainties, including, but not limited to, expropriation of property without fair compensation, changes in energy policies or the personnel administering them, nationalization, currency fluctuations and devaluations, exchange controls, royalty and tax increases and other risks arising out of foreign governmental sovereignty over areas in which our operations are conducted. Our proposed operations may also be affected by laws and policies of Canada affecting foreign trade, taxation and investment. In the event of a dispute arising in connection with our operations outside of Canada, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdictions of the courts of Canada or enforcing Canadian judgments in other jurisdictions. We may also be hindered or prevented from enforcing our rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, our exploration, development and production activities outside of Canada could be substantially impacted by factors beyond our control, any of which could have a material impact on us. We will seek to operate in such a manner as to minimize and mitigate our exposure to these risks. However, there can be no assurance that we will be successful in protecting ourselves from the impact of all of these risks.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity issuances, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our credit rating (if applicable);

- our existing debt leverage;
- interest rates;
- royalty rates;
- overall profitability of our existing operations and production;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. Moreover, future activities may require us to alter our capitalization significantly, including selling a portion or all of our interest in one or more projects. Our inability to access sufficient capital for our operations could have a material adverse effect on our business, financial condition, results of operations and prospects.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**") and the ongoing global credit and liquidity concerns. This volatility may in the future affect our ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver natural gas or crude oil to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance of our reserves from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our economic reserves. We, or the operators of our properties, might also elect not to produce from certain wells at lower prices.

North American crude oil price differentials are expected to continue to be volatile throughout 2015 which will have an impact on crude oil prices for Canadian producers. Although opportunities to move oil by rail continue to grow and will provide new outlets for access to North American refineries otherwise not reachable via existing pipeline infrastructure, supply in excess of current pipeline and refining capacity is expected to continue to exist. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts. A variety of new pipeline expansion projects to provide increased access to Gulf Coast refineries, have been announced and are in various stages of review and approval. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas acquisition, development and exploration activities. An extended period of low oil and natural gas prices or a further significant decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non core assets may be periodically disposed of so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non core assets, certain of our non core assets, if disposed of, may realize less than their carrying value on our financial statements.

Project Risks

Operators of our properties manage a variety of small and large projects in the conduct of capital activities and operations. Project delays may delay expected revenues from operations. Significant project cost over runs could make a project uneconomic. Their ability to execute projects and market oil and natural gas depends upon numerous factors beyond our, and their, control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;

- the availability of storage capacity;
- the availability of natural gas transportation and processing capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies including but not limited to the Bureau of Land Management, the Bureau of Indian Affairs, the Three Affiliated Tribes, and the NDIC in relation to our U.S. assets.

Because of these factors, we, or the operators of our properties, could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that we produce effectively.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities and pipeline systems, some of which we do not own, and by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. New gas flaring restrictions implemented by the NDIC in 2014 severely limit the amount of associated gas flaring that can take place on a well-by-well basis creating further potential restrictions on the ability to commence production from new wells without gas tie-in infrastructure in place. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. Furthermore, producers are increasingly turning to rail as an alternative means of oil transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the United States National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on our ability to process our production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods and reliability of delivery and storage.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be affected adversely and materially. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See: "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the Competition Act (Canada) and the Investment Canada Act (Canada).

Royalty Regimes

There can be no assurance that the federal, provincial and US Federal or state governments will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of our projects.

An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. Acquisitions of new assets in the US may require us to negotiate royalty rates with private landowners and there is a risk that such royalty rates may increase due to increased competition for such lands over time.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, state and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we, and the operators of our properties, are in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas emissions legislation at the regional, provincial, state or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This target is aligned with the United States target. These greenhouse gas emission reduction targets are not binding, however. Some of our significant facilities may ultimately be subject to future regional, provincial, state and/or federal climate change regulations to manage greenhouse gas emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gas and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the Canadian dollar equivalent price received by us from sales of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Accordingly, future Canadian/United States exchange rates could affect the future value of our reserves as determined by independent evaluators.

To the extent that we engage in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which we may contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a reduced amount available to fund our exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of our Common Shares.

Additional Funding Requirements

Cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and/or banking industry experienced unexpected and/or prolonged deterioration, our access to additional financing may be affected.

Because of global economic volatility, we may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Credit Facility Arrangements

The amount authorized under our senior bank revolving credit facility is dependent on the borrowing base determined by our lenders. We are required to comply with covenants under this facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under this facility, which could result in us being required to repay amounts owing thereunder. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to us. If we are unable to repay amounts owing under this facility, our lenders could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions, specifically our subordinated credit facility. In addition, this facility may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Our lenders use our reserves, commodity prices, applicable discount rate and other factors, to periodically determine our borrowing base. A material decline in commodity prices could reduce our borrowing base, reducing the funds available to us under this facility. This could result in the requirement to repay a portion, or all, of our bank indebtedness. In addition, we currently have access to a subordinated credit facility provided by our Chief Executive Officer and one of our shareholders. There can be no assurance that this facility will continue to be available to us in the future, or on terms that are acceptable to us.

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect us from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than expected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, we would not benefit from the fluctuating exchange rate if we had entered into such a hedging agreement.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us, and the operators of our properties, and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Our actual interest in properties may, accordingly, vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes which affect our title to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of the revenue received by us.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from our oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada and the United States have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of our net production revenue.

In addition, our oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have insurance to protect against the risk from terrorism.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities which may be dilutive.

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our business, financial condition, results of operations and prospects.

Dividends

We have not paid any dividends on our Common Shares since incorporation. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and our financial condition, the need for funds to finance ongoing operations and other considerations, as our Board of Directors considers relevant.

Litigation

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the relevant and all other applicable tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Seasonality

The level of activity in the Canadian and United States oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and local transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for our goods and services.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Conflicts of Interest

Certain of our directors or officers may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the Business Corporations Act (Alberta) which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with us to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *Business Corporations Act* (Alberta). See "*Directors and Officers - Conflicts of Interest*".

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Williston Basin, North Dakota. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Information and Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during our most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a security regulatory authority during the most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our Common Shares is TMX Equity Transfer Services, at its principal office in Toronto, Ontario.

MATERIAL CONTRACTS

Except for our credit facilities described under the heading "*Description of our Capital Structure*", we have not entered into any material contracts during the current financial year, the year ended December 31, 2014, or before the most recently completed financial year which are still in effect. Our material contracts have been filed under our profile on SEDAR at www.sedar.com.

EXPERTS

Interests of Experts

To our knowledge, no registered or beneficial interests, direct or indirect, in any of our securities or other property: (i) were held by NSAI or by the "designated professionals" (as defined in Form 51-102F2) of NSAI, when NSAI prepared the NSAI Report; (ii) were received by NSAI or the designated professionals of NSAI after NSAI prepared the NSAI Report; or (iii) is to be received by NSAI or the designated professionals of NSAI.

To our knowledge, no registered or beneficial interests, direct or indirect, in any of our securities or other property: (i) were held by McIntosh or by the "designated professionals" (as defined in Form 51-102F2) of McIntosh, when McIntosh prepared the McIntosh Report; (ii) were received by McIntosh or the designated professionals of McIntosh after McIntosh prepared the McIntosh Report; or (iii) is to be received by NSAI or the designated professionals of McIntosh.

KPMG LLP are our auditors and have confirmed that they are independent with respect to us within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

APPENDIX A
AUDIT COMMITTEE CHARTER

POLICY STATEMENT

It is the policy of PetroShale Inc. (the "**Corporation**") to establish and maintain an Audit Committee (the "**Committee**"), composed of independent directors, to assist the Board of Directors (the "**Board**") in carrying out their oversight responsibility for the Corporation's external audit, internal controls, disclosure, financial reporting and risk management.

The Committee's function is one of oversight only and shall not relieve management of its responsibilities.

The Corporation's external auditor shall report directly to the Committee.

COMPOSITION OF THE COMMITTEE

1. The Committee shall consist of three (3) directors.
2. Each director appointed to the Committee by the Board shall be independent as such term is defined in Section 1.4 of *Multilateral Instrument 52-110.*
3. Each member of the Committee shall be financially literate as such term is defined in Section 1.6 of Multilateral Instrument 52-110 and at least one (1) member shall have accounting or related financial management expertise.
4. The Board shall appoint the members of the Committee and may seek the advice and assistance of the Corporate Governance and Compensation Committee in identifying qualified candidates. The Board shall appoint one (1) member of the Committee to be the Chair of the Committee.
5. A director appointed by the Board to the Committee shall be a member of the Committee until replaced by the Board or until his or her resignation. A member shall cease to be a member of the Committee upon ceasing to be a director of the Corporation.
6. The Secretary of the Corporation shall be the Secretary of the Committee.

MEETINGS OF THE COMMITTEE

1. The Committee shall convene a minimum of four (4) times each year at such time and places as may be designated by the Chair of the Committee and whenever a meeting is requested by the Board, a member of the Committee, the external auditors, or a senior officer of the Corporation.
2. Notice of each meeting of the Committee shall be given to each member and to the external auditors, who shall be entitled to attend each meeting of the Committee and shall attend whenever requested to do so by a member of the Committee or the Secretary of the Committee.
3. Notice of a meeting of the Committee shall:
   (a) Be in writing.
   (b) State the nature of the business to be transacted at the meeting in reasonable detail.
   (c) To the extent practicable, be accompanied by copies of documentation to be considered at the meeting.
   (d) Be given at least forty-eight (48) hours' notice preceding the time stipulated for the meeting or such shorter period as the members of the Committee may permit.
4. A quorum for the transaction of business at a meeting of the Committee shall consist of two (2) members of the Committee.
5. A member of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities, provided it permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

6. In the absence of the Chair of the Committee, the members of the Committee shall choose one of the members present to be Chair of the meeting and, in the absence of the Secretary of the Committee, the members shall choose one of the persons present to be the Secretary of the meeting.

7. The Committee may invite the Chairman of the Board, other directors, senior management of the Corporation and other parties to attend meetings of the Committee; however, the Committee may meet separately with the external auditors or with invited management.

8. At each regular meeting of the Committee, the agenda shall include an opportunity for the members of the Committee to meet *in-camera*.

9. Minutes shall be kept of all meetings of the Committee and shall be signed by the Chair and the Secretary of the meeting.

10. Minutes of the meetings of the Committee shall be retained by the Secretary of the Corporation and shall be available, on request, to any member of the Board.

DUTIES AND RESPONSIBILITIES OF COMMITTEE MEMBERS

1. Committee members shall have and maintain a sufficient knowledge of company operations and changes in operations including the principal risks, systems and abilities of key personnel involved in financial reporting and disclosure processes to reasonably discharge their duties.

2. Committee members have an obligation to remain independent of the affairs of the Corporation and shall disclose any circumstances that create a conflict of interest with his or her role as a Committee member or may appear to create a conflict of interest.

DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

1. The Committee's primary duties and responsibilities are to:

    (a) Select and recommend the nomination and compensation of the external auditors.

    (b) Oversee the independence, work and performance of the Corporation's external auditors.

    (c) Review the principal risks that could impact the financial reporting of the Corporation and monitor how management is dealing with such risks.

    (d) Monitor the integrity of the Corporation's disclosure and financial reporting process and its system of internal controls regarding financial reporting and accounting compliance.

    (e) Oversee the resolution of any disagreements among external auditors, management and the internal auditing department, if any.

    (f) If requested by the Board and permitted by applicable law and policies, review and approve unaudited quarterly financial statements or other public disclosure documents containing financial information.

2. The Committee shall annually select and recommend to the Board the nomination of an external auditor, recommend the replacement of the current external auditor when circumstances warrant it and monitor the independence, work and performance of the external auditors. This shall include:

    (a) Considering the views of management in respect of the nomination of the external auditors.

    (b) Reviewing and recommending, for approval by the Board, the terms of the external auditors' engagement and audit plan, including the reasonableness of the proposed audit fees.

    (c) Pre-approving any engagement for non-audit services to be provided by the external auditors' firm or its affiliates, together with estimated fees. This shall involve considering the potential impact of such services on the independence of the external auditors.

    (d) When there is to be a change of external auditors, reviewing all issues and providing documentation related to the change, including the information to be included in the Notice of Change of Auditors and documentation called for under *National Instrument 51-102* as defined in Section 4.11 and the planned steps for an orderly transition.

(e) Reviewing all reportable events, including disagreements, unresolved issues and consultations with external auditors, as defined by applicable securities policies, on a routine basis, whether or not there is to be a change of external auditors.

(f) The Committee shall have the opportunity to meet with the external auditors apart from management at each regular meeting to receive assessments relating to audit scope limitations, management cooperation and any issues relating to financial competencies

3. In carrying out its primary duties and responsibilities, the Committee shall:

(a) Review the annual audit plan with the external auditors and with management.

(b) Discuss with management and the external auditors any proposed changes in major accounting policies or principles, the potential impact of significant risks and uncertainties on future operations, and key estimates and judgments of management that may be material to financial reporting.

(c) Review with management and with the external auditors significant financial reporting issues arising during the most recent fiscal period and the resolution or proposed resolution of such issues.

(d) Review any problems experienced or concerns expressed by the external auditors in performing an audit, including any restrictions imposed by management or significant accounting issues on which there was a disagreement with management.

(e) Review periodically with management the Corporation's disclosure controls and procedures as such term is defined in *Multilateral Instrument 52-109* and monitor the certification process set out therein.

(f) Review audited annual financial statements and related documents in conjunction with the report of the external auditors.

(g) Consider and review with management, the internal control memorandum or management letter containing the recommendations of the external auditors and management's response, if any, including an evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weaknesses.

(h) Review with management and the external auditors, if engaged to perform such a review, the quarterly unaudited financial statements before release to the public.

(i) Before release, review and if appropriate, recommend for approval by the Board, all public disclosure documents containing audited or unaudited financial information including any press release, annual report, annual information form, management discussion and analysis of operations, prospectus **[(and all documents which may be incorporated by reference into such prospectus)] [NTD: Nicole, I thought we should remove this because I can't imagine a director ever reading all the material agreements being incorporated by reference]** and all other securities offering documents of the Corporation.

(j) Review periodically with management the internal procedures implemented to review any other public disclosure of financial information extracted or derived from the Corporation's financial statements.

(k) Approve the hiring of any partners, employees or former partners and employees of the Corporation's present and former external auditor.

4. In addition, the Committee shall:

(a) Oversee the receipt, review and follow-up of questions, concerns or complaints pursuant to the Corporation's Code of Business Conduct and Ethics and the procedures set out in Appendix "A" thereto.

(b) The Committee shall periodically review the manner of delegation and limits of authority that management has implemented throughout the Corporation.

(c) The Committee shall review changes in accounting principles, regulations and emerging issues that may be relevant to the Corporation.

(d) In conjunction with the Corporate Governance and Compensation Committee, monitor financial and accounting personnel succession planning within the Corporation and review the appointments of the Chief Financial Officer and any key financial managers who are involved in the financial reporting process.

(e) Inquire into and determine the appropriate resolution of any conflict of interest in respect of audit or financial matters.

(f) Quarterly, review any legal matter that could have a significant impact on the Corporation's financial statements, and any enquiries received from regulators, or government agencies.

(g) Report to the Board, at the earliest opportunity after each meeting, the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate. In particular, the Committee shall make recommendations to the Board in connection with: (i) the appointment of external auditors; (ii) approval of financial statements, MD&A and related disclosure documents; and (iii) changes in significant accounting policies.

(h) Periodically assess the performance of the Committee.

RESOURCES AND AUTHORITY

1. The Committee will be provided with resources commensurate with the duties and responsibilities assigned to it by the Board including administrative support. If deemed necessary by the Committee, it will have the discretion to institute investigations of improprieties or suspected improprieties, including the standing authority to retain independent counsel or advisors and to set their compensation.

2. The Committee shall have the authority to:

   (a) Inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates.

   (b) Discuss with any officer of the Corporation, its subsidiaries and affiliates, the Chief Financial Officer and senior staff of the Corporation, any affected party and the external auditors, such accounts, records and other matters as any member of the Committee considers necessary and appropriate.

   (c) Communicate directly with the internal and external auditors.

   (d) Retain independent external advisors.

Approved on March 27, 2015

APPENDIX B
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS
FORM 51-101F2

To the board of directors of PetroShale Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Netherland, Sewell & Associates, Inc.	Reserve report of PetroShale (US) Inc. February 16, 2015	United States	-	142,039.8	-	142,039.8
Jim McIntosh Petroleum Engineering Ltd.	PetroShale December 31, 2014 Reserves Evaluation March 13, 2015	Canada	-	1,862.5	-	1,862.5

In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

5. We have no responsibility to update our reports for events and circumstances occurring after their respective preparation dates.

6. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

(signed) "C.H. (Scott) Rees III"
NETHERLAND, SEWELL, & ASSOCIATES, INC.

(signed) "John G. Hattner"
NETHERLAND, SEWELL, & ASSOCIATES, INC.

(signed) "Dan Paul Smith"
NETHERLAND, SEWELL, & ASSOCIATES, INC.

(signed) "J.W. (Jim) McIntosh, P.Eng."
JIM MCINTOSH PETROLEUM ENGINEERING LTD.

APPENDIX C
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE
FORM 51-101F3

Management of PetroShale Inc. ("**PetroShale**") is responsible for the preparation and disclosure of information with respect to PetroShale's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated PetroShales's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of PetroShale has:

(a) reviewed PetroShale's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed PetroShale's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F2 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "*M. Bruce Chernoff* "
M. Bruce Chernoff
Executive Chairman, Chief Executive Officer and Director

(signed) "*Ken McCagherty*"
Ken McCagherty
Director, Chair of the Reserves Committee and Member of the Audit Committee

(signed) "*Antonio Izzo*"
Antonio Izzo
Vice President, Business Development

(signed) "*Jacob Roorda*"
Jacob Roorda
Director and Member of the Audit Committee, the Reserves Committee and the Corporate Governance and Compensation Committee

March 27, 2015