MANITOK ENERGY INC.

Year Ended December 31, 2013

ANNUAL INFORMATION FORM

April 23, 2014

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DEFINITIONS

Definitions

In this Annual Information Form, certain terms are used but not defined herein. These terms are defined in NI 51-101 and CSA Staff Notice 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA Staff Notice 51-324. The capitalized terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act* (Alberta);

"**Annual Information Form**" means this Annual Information Form dated April 23, 2014;

"**Board**" means the board of directors of the Corporation;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook;

"**Crown**" means the Government of Alberta;

"**CSA Staff Notice 51-324**" means the Canadian Securities Administrators Staff Notice 51-324 *Glossary to NI 51-101*;

"**gross**" means: (a) in relation to the Corporation's interest in production or reserves, the Corporation's working interest (operating or non-operating) share before deduction of royalty obligations and without including any royalty interests; (b) in relation to wells, the total number of wells in which the Corporation has an interest; and (c) in relation to properties, the total area in which the Corporation has an interest;

"**GAAP**" means generally accepted accounting principles which is International Financial Reporting Standards, consistently applied;

"**Manitok**" or the "**Corporation**" means Manitok Energy Inc.;

"**Manitok Shares**" means common shares in the capital of the Corporation;

"**net**" means (a) in relation to the Corporation's interest in production or reserves, the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in such production or reserves; (b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of the Corporation's gross wells; and (c) in relation to properties, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation;

"**NI 51-101**" means National Instrument 51-101 *Standard of Disclosures for Oil and Gas Activities*;

"**P&NG**" means petroleum and natural gas;

"**reserves**" means estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates:

(a) 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; and

(b) 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;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval;

"**Sproule**" means Sproule Associates Limited, independent qualified reserves evaluators and auditors of Calgary, Alberta;

"**Sproule Evaluation**" means the Reserves Assessment and Economic Evaluation effective December 31, 2013 in respect of Manitok's oil and natural gas properties, which evaluation is contained in a report prepared by Sproule dated April 11, 2014;

"**Sproule Price Forecast**" means Sproule's December 31, 2013 forecast price assumptions set out in a table under "Reserves Data and Other Oil and Gas Information";

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations promulgated thereunder;

"**TSX**" means Toronto Stock Exchange;

"**TSX-V**" means TSX Venture Exchange;

"**WCSB**" means the vast sedimentary basin underlying western Canada that is the source of most of western Canada's current oil and natural gas production; and

"**working interest**" means a percentage of ownership in an oil and natural gas property, obligating the owner to share in the costs of exploration, development and operations and granting the owner the right to share in production revenues after royalties are paid.

ABBREVIATIONS, CONVERSIONS AND CONVENTIONS

Abbreviations

The abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	mcf	thousand cubic feet
bbls	barrels	Mmcf	million cubic feet
bbls/d	barrels per day	mcf/d	thousand cubic feet per day
Mbbls	thousand barrels	Mmcf/d	million cubic feet per day
NGLs	natural gas liquids	mcfe	thousand cubic feet equivalent
boe	barrels of oil equivalent	mcfe/d	thousand cubic feet equivalent per day
boe/d	barrels of oil equivalent per day	GJ	Gigajoule
Mboe	thousand barrels of oil equivalent	GJ/d	Gigajoules per day
		mmbtu	million British thermal units

Other

AECO	benchmark natural gas price determined at the AECO 'C' hub in southeast Alberta
WTI	West Texas Intermediate crude oil, a benchmark oil price determined at Cushing, Oklahoma
°API	the measure of the density or gravity of liquid petroleum products
M$	thousands of dollars

Conversions

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

From	To	Multiply By
mcf	cubic metres	28.174
mcf	GJ	1.055
cubic metres	cubic feet	35.494
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
sections	acres	640
sections	hectares	256

Conventions

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in accordance with GAAP.

ADVISORIES

Non-GAAP Measures

This Annual Information Form contains references to measures used in the oil and natural gas industry such as "funds from operations", "operating netback" and "working capital". These measures do not have any standardized meanings prescribed by GAAP and therefore should not be considered in isolation. These reported amounts and their underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of other companies where similar terminology is used. Where these measures are used they should be given careful consideration by the reader. These measures have been described and presented in this Annual Information Form in order to provide shareholders and potential investors with additional information regarding the Corporation’s liquidity and its ability to generate funds to finance its operations.

Funds from operations should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net earnings as determined in accordance with GAAP, as an indicator of Manitok's performance or liquidity. Funds from operations is used by Manitok to evaluate operating results and Manitok's ability to generate cash flow to fund capital expenditures and repay indebtedness. Funds from operations denotes cash flow from operating activities as it appears on the Corporation's Statement of Cash Flows before decommissioning expenditures and changes in non-cash operating working capital. Funds from operations is also derived from net income (loss) plus non-cash items including deferred income tax expense, depletion and depreciation expense, exploration and evaluation expense, impairment expense, stock-based compensation expense, accretion expense, acquisition-related expenses, unrealized gains or losses on financial instruments and gains or losses on asset divestitures. Operating netback denotes P&NG revenue and realized gain (loss) on financial instruments less royalty expenses, operating expenses and transportation and marketing expenses calculated on a per boe basis. Working capital includes current assets less current liabilities excluding the current portion of the amount drawn on the credit facilities, the fair value of financial instruments and the deferred premium on financial instruments.

Boe Equivalent

The term barrels of oil equivalent ("**boe**") may be misleading, particularly if used in isolation. Per boe amounts have been calculated using a conversion ratio of six thousand cubic feet (6 mcf) of natural gas to one barrel (1 bbl) of crude oil. The boe conversion ratio of 6 mcf to 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 that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Forward Looking Information

This Annual Information Form contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to future events or future performance and is based upon the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to "reserves" or "resources" contained, among other places, under "Reserves Data and Other Oil and Gas Information" is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves or resources exist in the quantities estimated and that they will be commercially viable to produce in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information. In particular, this Annual Information Form contains forward-looking information, including among other places, under the headings "Description of the Business", "Reserves Data and Other Information" and "Risk Factors". This forward-looking information includes but is not limited to statements regarding: the Corporation's intention to drill and complete future wells; estimates of recoverable reserves and resource volumes; planned production increases; planned 2014 capital spending and sources of funding; expected results from the Corporation's portfolio of P&NG assets; the quantity and development of P&NG reserves and resources; future net cash flows and discounted cash flows; expected operating, services and environmental compliance costs; royalty rates and incentives; and treatment under tax laws. Such statements reflect the Corporation's forecasts, estimates and expectations, as they relate to the Corporation's current views based on their experience and expertise with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation's actual results, performance or achievements to be materially different from any future results, performance or achievements that may be expressed or implied by such forward-looking statements. Given these risks and uncertainties, readers are cautioned not to place undue reliance on such forward-looking statements.

By their nature, forward-looking information involves a variety of assumptions, known and unknown risks and uncertainties, and other factors, which may cause actual results, levels of activity, and achievements to differ materially from those expressed or implied by such statements. The material factors and assumptions used to develop the forward-looking statements herein include, but are not limited to, the following; future commodity prices, currency exchange rates, inflation rates, well production rates, well drainage areas, success rates for future drilling, availability of labour and services, interest rates, future availability of debt and equity financing being at levels and costs that allow the Corporation to manage, operate and finance its business, develop its properties and meet its future obligations. With respect to estimates of reserves and resource volumes, a key assumption is the validity of the data used by Sproule in its independent reserves and resource evaluations. With respect to future wells to be drilled, a key assumption is that geological and other technical interpretations performed by the Corporation's technical staff, which indicate that commercially economic reserves can be recovered from the Corporation's land as a result of drilling such future wells, are valid. Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. Although the Corporation believes that the expectations reflected in the forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ materially from those anticipated.

Forward-looking information necessarily involves both known and unknown risks associated with P&NG exploration, production, transportation and marketing such as uncertainty of geological and technical data, imprecision of reserves estimates, operational risks, environmental risks, loss of market demand, general economic conditions affecting the ability to access sufficient capital, changes in governmental regulation of the oil and gas industry and competition from others for scarce resources.

The foregoing list of risk factors is not exhaustive. Additional information on these and other risk factors that could affect operations or financial results are included under the heading "Risk Factors" in this Annual Information Form and in other reports filed with Canadian securities regulatory authorities. Forward-looking information is based on estimates and opinions of management at the time the information is presented. The Corporation is not under any duty to update and does not intend or assume any obligation to update the forward-looking information after the date of this Annual Information Form to conform such information to actual results or to changes in the Corporation's plans or expectations, except as otherwise required by applicable securities laws. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are expressly qualified in their entirety by these cautionary statements.

CORPORATE STRUCTURE

Manitok was formed by the amalgamation of Desco Resources Inc. ("**Desco**") and Manitok Exploration Inc. ("**MEX**") under the ABCA on July 8, 2010 (the "**Amalgamation**").

Desco was incorporated under the ABCA on July 8, 2009. Prior to the Amalgamation, Desco was a reporting issuer in the provinces of British Columbia, Alberta, Manitoba and Ontario and was listed on the TSX-V under the trading symbol "DSR.P" as a "capital pool company".

MEX was incorporated under the ABCA on April 20, 2005 as a private company based in Calgary, Alberta. Prior to the Amalgamation, MEX was engaged in the acquisition, exploration, development and production of P&NG in the WCSB.

Desco and MEX agreed to amalgamate and form "Manitok Energy Inc." pursuant to the terms of an amalgamation agreement dated effective April 1, 2010. The Amalgamation was approved by the respective shareholders of Desco and MEX on June 25, 2010.

The Corporation's head office is located at Suite 2500, 639 – 5th Avenue S.W., Calgary, Alberta, T2P 0M9, and its registered office is located at Suite 1600, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

The Corporation does not have any subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

Objectives

Manitok is a public P&NG exploration and development company focused on conventional P&NG in the WCSB. The stated business objectives of the Corporation consist of the following:

(a) to develop and exploit P&NG production and drilling opportunities on Manitok's current land holdings in order to maximize production, reserves and funds from operations; and

(b) to continue to acquire land, production, development and exploration opportunities in the WCSB, focusing in particular on the foothills and southeast Alberta.

Three Year History

2011

On April 14, 2011, the Corporation closed an equity financing, completed by way of a short form prospectus, for the sale of 17,968,750 Manitok Shares issued at a price of $1.60 per Manitok Share for net proceeds of approximately $26.7 million (the "**April 2011 Financing**"). Proceeds of the April 2011 Financing were used to fund the Corporation's drilling program and the central Alberta foothills (as defined below).

On October 31, 2011, the Corporation closed an acquisition of P&NG assets in the central Alberta foothills area, with an effective date of July 1, 2011, for total cash consideration of approximately $41.9 million after final closing adjustments and acquisition-related expenses (the "**Central Alberta Foothills Acquisition**"). The consideration paid by the Corporation for the assets was financed by existing cash balances and bank indebtedness. Concurrent with the closing of the Central Alberta Foothills Acquisition, the borrowing base limit of the Corporation's revolving credit facility was increased from $5.0 million to $30.0 million. The Central Alberta Foothills Acquisition included approximately 1,300 boe/d (94% natural gas).

On December 5, 2011, the Corporation closed a bought deal equity financing, completed by way of a short form prospectus, for the sale of 6,500,000 Manitok Shares issued at a price of $1.85 per Manitok Share and 3,635,000 Manitok Shares issued on a "flow-through" basis under the Tax Act in respect of Canadian exploration expense

("**Manitok CEE Flow-through Shares**") at a price of $2.20 per Manitok CEE Flow-through Share for aggregate net proceeds of approximately $18.5 million (the "**December 2011 Financing**"). Proceeds of the December 2011 Financing were used to temporarily eliminate bank indebtedness incurred on the Central Alberta Foothills Acquisition.

2012

On April 5, 2012, the Corporation closed a disposition of its entire working interest in its heavy oil assets in the Swimming area of Alberta, with an effective date of April 1, 2012, for total cash consideration of $13.2 million after final closing adjustments and related expenses (the "**Swimming Asset Divestiture**"). The Swimming Asset Divestiture included production of approximately 320 bbls/d of heavy oil, 13,794 net acres of land and seismic data. As a result of the Swimming Asset Divestiture, the Corporation's aggregate limit on its revolving credit facility was reduced from $30.0 million to $25.0 million. The net proceeds from the Swimming Asset Divestiture were used to temporarily eliminate the Corporation's bank indebtedness.

On June 15, 2012, the TSX-V authorized the Corporation's notice to make a normal course issuer bid (the "**2012 NCIB**") to purchase for cancellation up to 4.4 million Manitok Shares on the open market during the period from June 18, 2012 to June 17, 2013. On January 28, 2013 Manitok received approval from the TSX-V to increase the number of Manitok Shares that may be purchased under the 2012 NCIB to 5.8 million.

On October 16, 2012, the Corporation closed a bought deal equity financing, completed by way of a short form prospectus, for the sale of 3,026,316 Manitok Shares issued at a price of $1.90 per Manitok Share, 1,430,000 Manitok Shares issued on a "flow-through" basis under the Tax Act in respect of Canadian development expense ("**Manitok CDE Flow-through Shares**") at a price of $2.10 per Manitok CDE Flow-through Share and 4,000,000 Manitok CEE Flow-through Shares at a price of $2.30 per Manitok CEE Flow-through Share for aggregate net proceeds of approximately $16.5 million (the "**October 2012 Financing**"). Proceeds of the October 2012 Financing were used to temporarily eliminate bank indebtedness incurred on the 2012 capital expenditure program, which were partially redrawn to fund the Corporation's exploration and development activities in 2013.

2013

On June 26, 2013, Manitok completed a disposition of the majority of its royalty interest properties, with an effective date of April 1, 2013, for total cash consideration of approximately $3.3 million after closing adjustments ("**Royalty Asset Divestiture**"). The net proceeds from the Royalty Asset Divestiture will be used to partially fund the Corporation's ongoing capital expenditure program.

On June 18, 2013, the TSX-V authorized the Corporation's notice to make a normal course issuer bid (the "**2013 NCIB**") to purchase for cancellation up to 6.5 million Manitok Shares on the open market during the period from June 18, 2013 to June 17, 2014.

On October 21, 2013, the Corporation announced that it entered into a three year Lease Issuance and Drilling Commitment Agreement with Encana Corporation ("**Encana Agreement**"), whereby Manitok will acquire petroleum and natural gas leases covering 38,757 net hectares (96,893 net acres) in the Entice area of southeast Alberta for a total cash consideration of approximately $19.7 million, which included a bonus payment, lease rental costs and transaction fees. Pursuant to the Encana Agreement, Manitok has agreed to perform a minimum annual work program for each of the next three years, with an aggregate expenditure commitment of $106.0 million over a three year period, which includes $22.0 million in 2014, $33.0 million in 2015 and $51.0 million in 2016.

On October 21, 2013, the Corporation announced the appointment of Cameron G. Vouri as the Chief Operating Officer and Don Martin as the Vice President, Exploration – Plains. Mr. Martin will be responsible for the exploration and exploitation activities in the newly acquired lands in the Encana Agreement. The Corporation also announced the departure of Tim de Freitas as the Corporation's former Chief Operating Officer and Vice President, Exploration. On November 13, 2013, the Corporation announced the departure of Dorothy Else as the Corporation's former Vice President, Land.

On November 8, 2013, the Corporation closed a bought deal equity financing completed by way of a short form prospectus, for the sale of 1,403,000 Manitok CDE Flow-through Shares at a price of $3.35 per Manitok CDE Flow-through Share, and 5,638,900 Manitok CEE Flow-through Shares at $3.60 per Manitok CEE Flow-through Share for total net proceeds of approximately $23.5 million (the "**November 2013 Financing**"). Proceeds of the November 2013 Financing were used to temporarily eliminate bank indebtedness incurred on the 2013 capital expenditure program, which were partially redrawn and applied as needed to fund the Corporation's exploration and development activities in 2014.

On November 13, 2013, the National Bank of Canada increased the Corporation's credit facilities from $90.0 million to $105.0 million. The credit facilities are comprised of an $85.0 million revolving operating demand loan facility and a $20.0 million acquisition and development demand loan facility.

Recent Developments

Effective February 10, 2014, The Corporation filed a Notice of Change of Auditors in connection with the appointment of KPMG LLP as the auditor of the Corporation. At the request of the Corporation, Kenway Mack Slusarchuk Stewart LLP resigned as the auditor of the Corporation.

On February 28, 2014, the Corporation closed a disposition of its entire working interest in its assets in the central Alberta foothills, with an effective date of January 1, 2014, for total cash consideration of $22.0 million after closing adjustments and related expenses (the "**Central Alberta Foothills Divestiture**"). The Central Alberta Foothills Divestiture included approximately 777 boe/d (34% sweet natural gas, 60% sour natural gas and 6% liquids) of current production in the central Alberta foothills region and 36,000 net acres of undeveloped land.

On March 11, 2014, the TSX-V authorized the Corporation's notice to make a normal course issuer bid (the "**2014 NCIB**") to purchase for cancellation up to 6.8 million Manitok Shares on the open market during the period from March 17, 2014 to March 16, 2015.

On March 25, 2014, the Corporation announced the appointment of Tim Jerhoff as the Vice President, Production and Engineering. The Corporation also announced the departure of Yvonne McLeod as the Corporation's former Vice President, Drilling and Facilities.

Strategy

Manitok's corporate strategy is that of being an "early mover" in the exploitation and exploration of oil and natural gas in both of its core areas in Alberta. The Corporation is focusing on structural Cardium and Mannville plays in the Alberta foothills and lower Mannville oil in southeast Alberta. At this time, the number of competitors in the foothills is relatively low due to the technical experience required to understand and execute drilling programs in the foothills. That has enabled the Corporation to assemble a large undeveloped land base in the foothills which is prospective for both Cardium oil and Mannville gas. Manitok has also established a large land base, prospective for lower Mannville oil, in southeast Alberta through the Encana Agreement. Manitok will create shareholder value through the development of its assets, and the acquisition of additional assets, within its two core areas.

DESCRIPTION OF THE BUSINESS

General

The Corporation is a public oil and gas exploration and development company focusing on conventional oil and gas reservoirs in the Canadian foothills and southeast Alberta. The Corporation will utilize its experience to develop the untapped conventional oil and liquids-rich natural gas pools in both the foothills and southeast Alberta areas of the WCSB. The Corporation's business model envisages continuous growth through drilling and the acquisition of suitable properties via asset purchases, farm-ins and corporate acquisitions or mergers.

Principal Properties

The following is a description of the Corporation's principal P&NG properties as at December 31, 2013. Unless otherwise noted, production stated is the average gross sales volumes for the period indicated in respect of the Corporation's working interest before the deduction of royalties and before royalty income volumes. Unless otherwise specified, gross and net acreage and well information is at December 31, 2013.

Cordel/Stolberg Area, Alberta

The Cordel/Stolberg property is about 16 km north of the hamlet of Nordegg, Alberta. The area has been exploited for its deep sour natural gas by several major P&NG companies over the last 30 years. While there are many other liquids-rich natural gas targets in the area, due to very high crude oil prices, Manitok has refocused its capital in the Cardium Formation at Cordel/Stolberg. In this area, the Cardium is a conventional reservoir, which has been deformed in complex geological structures. In some cases, the productive Cardium Formation has been deformed to depths as shallow as 800 metres. In these sandstone and conglomerate reservoirs, oil quality ranges up to 52° API. The very light oil is unusual in the basin, and demands a premium to the benchmark price. The reservoir will be exploited primarily with horizontal drilling. While historically the Cardium has not required stimulation in this area, the Corporation may elect to stimulate should the drill bit encounter lower permeability reservoirs. As at December 31, 2013, the Corporation had 30 (14.5 net) producing wells in the area, with 18 (11.5 net) from the Cardium Formation.

Entice Area, southeast Alberta

In order to increase both the scalability and visibility of Manitok's oil drilling inventory, along with reducing its drilling risk profile, Manitok has acquired leases in a second core area pursuant to the Encana Agreement. The Entice area lands are contiguous, which will provide for efficiencies in both capital and operating expenditures and have about 250 well penetrations, as deep as the Devonian formation, with logs and drill stem tests. Using such data, along with extensive 3D seismic coverage, Manitok has identified potential opportunities in several zones in the Entice area which has multi-stacked pay and it is anticipated that Manitok will be able to test multiple zones with many wellbores which reduces its drilling risk. Manitok believes that the Entice area lands are highly prospective for extensive reserves of oil and gas. The capital costs of drilling in the area are considerably less than in the foothills, with all-in well costs generally ranging from $1.0 million to $3.0 million depending on the depth drilled and completion type.

Greater Hinton Area, Alberta

This area comprises a large area with a variety of shallow natural gas, oil and liquids-rich natural gas prospects. Key properties include Basing, Banshee, Brown Creek, Cabin Creek, Lovett and Solomon in the Alberta foothills. Manitok also owns extensive pipeline systems, compressors and a 20% interest in a sweet natural gas plant in the Hanlan area of Alberta. These facilities significantly reduce operational costs, and therefore increase the value of the drilling projects. On February 28, 2014, the Corporation closed the Central Alberta Foothills Divestiture which related to the majority of the assets in the Greater Hinton area.

Production

Production for the year ended December 31, 2013 averaged 4,113 boe/d (52% light oil and liquids), compared to average production of 2,389 boe/d (36% light oil and liquids) in the year ended December 31, 2012. The increase in production of 72% was due mainly to the 2013 capital expenditure program in the Stolberg area of Alberta. For the year ended December 31, 2013, 18% of P&NG sales from the Corporation's properties before royalties was derived from natural gas and 82% was from crude oil and NGLs. Production is sold to marketers at delivery points in or close to the producing field.

Product Sales Revenues

The products produced and sold by the Corporation are light crude oil, natural gas and NGLs. Most of these products are sold on a short-term basis at prices that are a function of current market prices. None of the Corporation's products are sold to non-arm's length parties.

The following table sets forth the aggregate sales of the products produced by the Corporation during the years ended December 31, 2013 and 2012:

Product	2013 Revenue (M$)	2012 Revenue (M$)
Natural Gas	15,528	8,191
Light Oil	67,655	24,047
Heavy Oil	-	2,621
NGLs	2,388	2,155

Specialized Skill and Knowledge

The Corporation's business requires the application of extremely high levels of technical skill in the areas of geology, geophysics and reservoir engineering, well drilling and completions and well production operations. Manitok has assembled a team of skilled experts who provide the technical skills required to succeed in its business. See "*Risk Factors – Reliance on Key Personnel*".

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. The Corporation competes with numerous other participants in the search for and the acquisition of lands, P&NG projects and properties. The Corporation's competitors include companies which have greater technical and financial resources, as well as more staff and facilities, than the Corporation. Manitok believes that it has a competitive advantage in its focus areas based upon the facilities and land base it controls and the experience it has developed on the plays it pursues. See "*Risk Factors – Competition*".

Seasonal Factors

The exploration for and development of P&NG reserves in the Corporation's focus areas are dependent on access to areas where operational activities are to be conducted. Seasonal weather variations, including break-up, can delay such access. See *"Risk Factors – Seasonality*".

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on funds from operations and overall competitiveness. See "*Risk Factors – Environment and Regulatory Risks*" and "*Information Concerning the Oil and Natural Gas Industry – Environmental Regulation*".

Personnel

At December 31, 2013, the Corporation had: 29 full-time employees, six part-time employees and five contract service providers in its head office; six employees and one contract service providers in its field office in the Stolberg area of Alberta; and two employees and four contract service providers in its field office in Hinton, Alberta. The Corporation hires skilled contractors to perform drilling operations, well completions and other field service operations. See "*Risk Factors – Reliance on Key Personnel*".

Environmental Policies

The Corporation has an active program to monitor and comply with health, safety and environmental laws, rules and regulations applicable to its operations. The Corporation's policies require operational activities to be conducted in a manner which meet or exceed regulatory requirements and industry standards to safeguard the environment and protect employees, contractors and the public at large. All employees receive pertinent health, safety and environmental training for their respective roles. The Corporation conducts regularly scheduled safety meetings, operational audits and assessments to identify risks and take steps to reduce or prevent accidents. See "*Risk Factors –Environmental and Regulatory Risks*".

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

- world market forces and more specifically, the North American market forces shift in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
- political conditions, including the risk of hostilities throughout the world;
- increases or decreases in crude oil quality and market differentials;
- the impact of changes in the exchange rate between Canada and US dollars on prices received by the Corporation for its crude oil and natural gas;
- global and domestic economic and weather conditions;
- price and availability of alternative fuels; and
- the effect of energy conservation measures and government regulations.

RISK FACTORS

The Corporation’s operations are exposed to a number of risks, some that impact the oil and gas industry as a whole and others that are unique to the Corporation. We have identified risks in four main categories: financial, operational, environmental and regulatory, and reputation. The impact of any risk or a combination of risks in these four categories may adversely affect the Corporation’s business, reputation, financial condition, results of operations and funds from operations, which may materially affect the market price of the Corporation’s securities. The holding of securities of the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision regarding the Corporation's securities.

Financial Risks

Access to Credit Markets

Due to the nature of the Corporation's business, it is necessary from time to time for the Corporation to access other sources of capital beyond its internally generated funds from operations in order to fund the development and acquisition of its long term asset base. As part of this strategy, the Corporation obtains a portion of this necessary capital by incurring debt and therefore the Corporation is dependent to a certain extent on continued availability of the credit markets. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing in the future to take advantage of business opportunities that may arise.

The continued availability of the credit markets for the Corporation is primarily dependent on the state of the economy and the health of the banking industry in Canada and the United States. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to credit markets may contract or disappear altogether. The Corporation tries to mitigate this risk by dealing with reputable lenders and tries to structure its lending agreements to give it the most flexibility possible should these situations arise. However, situations that give rise to credit markets tightening or disappearing are largely beyond the Corporation's control.

The Corporation is also dependent, to a certain extent, on continued access to equity capital markets. The Corporation is listed on the TSX-V and maintains an active investor relations program. Continued access to capital is dependent on the Corporation's ability to continue to perform at a level that meets or exceeds market expectations.

Commodity Price Volatility

Manitok's liquidity and funds from operations is largely impacted by P&NG commodity prices. Oil and natural gas prices fluctuate in response to changes in the supply and demand for crude oil and natural gas, market uncertainty and a variety of additional factors that are largely beyond the Corporation's control. The Corporation has hedged a portion of its P&NG production at the date hereof and will continue to monitor the derivative market for opportunities to increase its hedged position. If there is a significant deterioration in the price it receives for P&NG, the Corporation will consider reducing its capital spending or accessing alternate sources of capital.

The Corporation enters into agreements to receive fixed prices for its P&NG production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, the Corporation 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, the Corporation's hedging arrangements may expose the Corporation to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedging 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 P&NG commodity prices.

Uncertainty of Reserves Estimates

There are a number of uncertainties inherent in estimating the quantities of reserves and resources, including many factors beyond the control of the Corporation. In general, estimates of economically recoverable P&NG reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by government agencies and future operating costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable P&NG reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineer at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Corporation with respect to these reserves will vary from such estimates, and such variances could be material. Estimates with respect to proved plus probable 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 that actual production history. 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 will result in variations, which may be substantial, in the estimated reserves. Consistent with the Canadian securities disclosure legislation and policies, the Corporation has used forecast prices and costs in calculating reserve quantities. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for P&NG, curtailments or increases in consumption by P&NG purchasers, changes in government regulations or taxation and the impact of inflation on costs. NI 51-101 requires the inclusion of the following statement in estimates of future net revenues based on reserves estimates; "estimates of future net revenues, whether discounted of not, does not represent fair market value".

Counterparty Credit Risk

The Corporation assumes customer credit risk associated with P&NG sales and joint venture participants. To mitigate this risk, the Corporation performs regular reviews of receivables to minimize default or non-payment and takes the majority of its production in kind.

Costs and Availability of Equipment and Services

Inflation is a risk common to all businesses in Canada. During times of high commodity prices for P&NG, there is a risk of substantially increased costs of operation, which impacts both the amount of capital required to perform operations and the netback the Corporation achieves from its production sales. Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment 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 the Corporation and may delay exploration and development activities. To the extent the Corporation is not the operator of its P&NG properties, the Corporation will be dependent on other operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators. Although the Corporation strives for continuous improvement in its planning, operations and procurement of materials, unexpected changes in the market for such equipment and services could negatively affect the Corporation's financial performance

Volatility of Market Price of Manitok Shares

The trading price of Manitok Shares is subject to volatility as a result of factors both related and unrelated to the financial performance of the Corporation. The market price of the Manitok Shares may respond to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. The market price of the Manitok Shares may also respond to factors unrelated to the Corporation's performance such as commodity prices and the market perception of the attractiveness of the oil and gas industry.

Insurance

The Corporation obtains insurance in accordance with industry standards to address business risks, however such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, certain risks may not in all circumstances be insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on its financial position, results of operations or prospects.

Variations in Foreign Exchange Rates and Interest Rates

The Corporation is exposed to foreign currency fluctuations as its Canadian revenues are strongly linked to US dollar denominated benchmark prices. The Corporation has not hedged any of its foreign exchange risk at the date hereof.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Manitok Shares.

Joint Ownership

Many of the Corporation's material assets are jointly held and are governed by contractual arrangements. As a result, certain decisions regarding these assets require the approval of the Corporation's partners. While the Corporation believes that it has prudent governance and contractual rights in place, there can be no assurance that the Corporation will not encounter disputes with partners that may impact operations or funds from operations.

Operations of the wells located on properties not operated by the Corporation are generally governed by operating agreements that typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of P&NG to the Corporation or to the operators, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of funds from operations available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

Income Taxes

The Corporation will file all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have a negative impact on current and future taxes payable and such impact may be material.

Borrowing

The Corporation's lenders have been provided with security over substantially all of the assets of the Corporation. If the Corporation becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell the Corporation's properties. The proceeds of any such sale would be applied to satisfy amounts owed to the Corporation's lenders and other creditors and only the remainder, if any, would be available to the Corporation.

Future Issuances of Manitok Shares

The Corporation may issue additional Manitok Shares in the future, which may dilute a shareholder's holdings in the Corporation. The Corporation's articles permit the issuance of an unlimited number of Manitok Shares and shareholders will have no pre-emptive rights in connection with such further issuances. The directors of the Corporation have the discretion to determine the terms of issue of further issuances of Manitok Shares. Also, additional Manitok Shares will be issued by the Corporation on the exercise of stock options under the Corporation's stock option plan.

Dividends

The Corporation is not obligated to pay dividends on the Manitok Shares. The payment of dividends is at the sole discretion of the Corporation's Board and, as at the date hereof, the Corporation has not paid dividends. In addition, the Corporation's credit facilities may restrict its ability to pay dividends, and thus the Corporation's ability to pay dividends on the Manitok Shares will depend on, among other things, the Corporation's level of indebtedness at the time of the proposed dividend and whether it is in compliance with such facilities. Any reduction or elimination of dividends could cause the market price of the Manitok Shares to decline and could further cause the Manitok Shares to become less liquid, which may result in losses to shareholders.

Operational Risks

Exploration, Development and Production

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time and the production therefrom, will decline over time as such existing reserves are exploited.

Hydraulic fracturing involves the injection of fluid, sand and additives under pressure into rock formations to improve or encourage hydrocarbon production. The use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs. The Corporation anticipates that federal and provincial regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. The implementation of new regulations with respect to water usage of hydraulic fracturing generally could lead to operational delays, as well as increase the Corporation's costs of compliance, its operating costs, and may negatively impact the Corporation's prospects, any of which could have a material adverse effect on the Corporation's business, financial condition and results of operations. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves. The Corporation conducts its fracturing operations with reputable service providers, with due regard for the potential impact on the environment and closely monitors and complies with the regulatory regime.

The Corporation remains subject to the risk that the production rate of significant wells may decrease in an unpredictable and uncontrollable manner, which could result in a material decrease in the Corporation's overall production and associated funds from operations.

Availability of Processing and Pipeline Capacity

The Corporation is subject to deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and the possible inability to secure space on gathering systems that deliver production to processing facilities and on pipelines which deliver oil and natural gas to commercial markets. The majority of the Corporation's production is reliant on third party infrastructure prior to it being ready for transfer at designated commodity sales points. There is a risk that this infrastructure could fail and cause a significant portion of the Corporation's production to be shut-in and unable to be sold, which could have a material adverse effect on the Corporation's available funds from operations. The Corporation mitigates this risk by purchasing contingent business interruption insurance policies for its significant third party infrastructure.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of oil and gas properties in the ordinary course of business. Typically, once an opportunity is identified, a review of available information relating to the properties is conducted with most of the review effort being focused on the most significant properties. There is a risk that even a detailed review of records and properties may not necessarily reveal every existing or potential problem, nor will it permit the Corporation to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Corporation often assumes certain environmental and other risk liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of oil and gas reserves and actual future production rates and associated costs with respect to acquired properties, and actual results may vary substantially from those assumed in estimates. Management continually assesses the value of the Corporation's assets and may dispose of non-core assets so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market, there is a risk that certain non-core assets could realize less than their carrying value in the Corporation's financial statements. The Corporation manages the risk associated with acquisitions and disposition through a careful due diligence review of available information in order to make prudent business decisions.

Health, Safety and Environment Risks

Health, safety and environment risks influence the workforce, operating costs and the establishment of regulatory standards. These risks include, but are not limited to, encountering unexpected formations or pressures; premature declines of reservoirs; blow-outs; equipment failures; human error or wilful misconduct by field workers; other accidents such as, wellbore cratering, sour gas releases, uncontrollable flows of oil, natural gas or fluid spills; adverse weather conditions, pollution, fires and other environmental risks. The Corporation provides staff with the training and resources required to complete work safely and effectively; incorporates hazard assessment and risk management as an integral part of everyday operations; monitors performance to ensure its operations comply with legal obligations and internal standards; and identifies and manages environmental liabilities associated with its existing asset base. The Corporation has a site inspection program and a corrosion risk management program designed to ensure compliance with environmental laws and regulations. The Corporation carries insurance to cover a portion of property losses and liability to third parties and business interruption resulting from unusual events.

The Corporation is subject to the risk that the unexpected failure of its equipment used in drilling, completing or producing wells or in transporting production could result in release of fluid substances that pollute or contaminate lands at or near its facilities, which could result in significant liability to the Corporation for costs of clean up, remediation and reclamation of the contaminated lands. The Corporation conducts its operations with due regard for the potential impact on the environment. This includes hiring skilled personnel, providing adequate training to all staff involved with operations, and by retaining expert advice and assistance to deal with environmental remediation and reclamation work where such expertise is required.

Reserve Replacement

P&NG reserves naturally deplete as they are produced over time. The success of the Corporation's business is highly dependent on its ability to acquire or discover new reserves in a cost effective manner. Substantially all of the Corporation's funds from operations is derived from the sale of the P&NG reserves it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its funds from operations on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. In order to mitigate this risk, the Corporation employs a competent and experienced team of P&NG professionals and closely monitors the capital expenditures made for the purposes of increasing its P&NG reserves.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access and, as a result, reduced operations or a cessation of operations. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain P&NG 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 drilling and production activity.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences or leases held by others. If the Corporation or the holder of the licence or lease fails to meet specific requirements 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 licences or leases may have a material adverse effect on results of operations and the business of the Corporation. To mitigate this risk, the Corporation carefully monitors its undeveloped land position and plans operations in order to keep key licences and leases from terminating or expiring.

Competition

The oil and natural gas industry is highly competitive particularly as it pertains to the exploration for and development of new sources of P&NG reserves. The industry also competes with other industries in supplying non-petroleum energy products. The Corporation actively competes for land, production and reserve acquisitions, exploration leases, licenses and concessions and skilled technical and operating personnel with a substantial number of other P&NG companies, many of which have greater financial resources than the Corporation.

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 to defeat the Corporation's ownership claims, which could result in the Corporation losing all or a portion of its right title and interest in and to the properties to which the title defects relate.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. An inability of the Corporation to effectively deal with this growth could have a material adverse impact on its business, operations and business prospects. Management mitigates this risk by continually implementing appropriate procedures and policies for its size, upgrading its systems, training its employees and providing effective supervision and management of its staff.

Reliance on Key Personnel

The loss of the services of key personnel could have a material adverse effect on the Corporation. The Corporation does not have "key person" insurance in effect for management and the contributions of these individuals to the Corporation's immediate operations is 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 the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Shareholders must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the Corporation's management.

Environment and Regulatory Risks

Environmental Regulation

The oil and gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of any such legislation may result in the imposition of fines or other penalties, as well as the responsibility to remedy environmental problems caused by the Corporation's operations. A serious breach could result in the Corporation being required to suspend operations or enter into an interim compliance measure which may restrict the Corporation's ability to conduct operations.

Political and economic events may significantly affect the scope and timing of climate change measures that are put in place. Some of the Corporation's facilities may be subject to future provincial or federal climate change regulations to manage emissions and there can be no assurance that the compliance costs will be immaterial. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas and increase costs.

Litigation

In the normal course of the Corporation's operations, it may become involved in, be 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, among other matters. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceeding, the proceeding could be costly and time-consuming and may divert the attention of management and key personnel from the Corporation's business operations. Specific disclosure of current legal proceedings is disclosed under the heading "*Legal Proceedings and Regulatory Actions*" in this Annual Information Form.

Changes in Legislation

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on the Corporation. As a P&NG producer, the Corporation is subject to a broad range of regulatory requirements. Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, extraordinary environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment. In addition, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil and reduce its price. The Corporation hires and retains skilled personnel that are knowledgeable regarding changes to the regulatory regime under which it operates.

All of the Corporation's properties are currently located within the province of Alberta. Although the Corporation believes it is making an economic investment at the time all of the upfront capital is invested in facilities or drilling, completing and equipping an oil or natural gas well, there is a risk that the Government of Alberta may at any point in the economic life of that project, expropriate without compensation a portion of the expected profit under a new royalty and/or tax regulation or regime with no grandfathering provisions. This may cause a particular project to become uneconomic once the new royalties or taxes take effect. This type of possible future government action is unpredictable and cannot be forecast by the Corporation.

Climate Change

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* and as a participant in the Copenhagen Accord, the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas ("**GHG**") emissions from 2005 levels by 2020. However, these GHG emission reduction targets are not binding. Although it is not the case today, the Corporation expects that some of its significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. If the Corporation becomes subject to GHG legislation, there can be no assurances that the compliance costs will be immaterial.

The Government of Alberta enacted the *Climate Change and Emissions Management Act* in response to concerns regarding GHG. The *Specified Gas Emitters Regulation* that accompanies the Act came into force in 2007 and requires large industrial facility emitters of GHG to reduce GHG emissions intensities by 12% below a baseline derived from the average of 2003-2005 emissions. The Corporation is not considered a large industrial emitter under this legislation and, as such, the Corporation is not subject to the costs of complying with the *Specified Gas Emitters Regulation.*

Potential Conflicts of Interest

Some of the directors of the Corporation are also directors of other P&NG companies, which may from time to time be in competition with the Corporation for working interest partners, property acquisitions, or other limited resources. Where required by law, appropriate disclosure of such conflicts will be made by the applicable directors. In particular, the Corporation follows the provisions of the ABCA. These provisions state that in the event that a director has an interest in a contract or proposed contract or agreement, such 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 permitted by the ABCA.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of the Corporation's assets; however, if a claim arose and was successful, it could have an adverse effect on the Corporation and its operations.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

This statement of reserves data and other oil and gas information of Manitok is dated April 11, 2014. The effective date of the reserves and future net revenues information is December 31, 2013, unless otherwise indicated, and the preparation date is December 2013 to April 2014.

Disclosure of Reserves Data

Sproule, independent qualified reserves evaluators and auditors of Calgary, Alberta prepared the Sproule Evaluation. Sproule has confirmed to the Reserve and Occupational Health and Safety Committee of the Board that the Sproule Evaluation has been prepared in accordance with the standards contained in the COGE Handbook and NI 51-101.

In preparing its report, Sproule obtained basic information from Manitok, which included land data, well and accounting information, reservoir and geological studies, estimates of on-stream dates for certain properties, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluation, and upon which the Sproule Evaluation is based, were obtained from public records, other operators and from Sproule's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by Sproule.

For the purposes of properly understanding the reserves and future net revenue data presented from Sproule's Evaluation it is important to understand each of the following:

- Due to rounding, certain columns may not add exactly.
- The net present value of future net revenue attributable to the Corporation's reserves is based on the Sproule Price Forecast and is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, transportation and marketing costs, development costs, other income, future capital expenditures and well abandonment costs for only those wells assigned reserves by Sproule.
- It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by Sproule represent the fair market value of those reserves.
- The recovery and reserve estimates of the Corporation's oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. Reservoir performance after December 31, 2013 may justify revision of assessed reserves, either upward or downward.
- The tables below are a summary of the oil, NGLs and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Evaluation based on the Sproule Price Forecast and represent 100% of the Corporation's oil and natural gas assets.
- The Sproule Evaluation is based on certain factual data supplied by the Corporation and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to Manitok's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Manitok to Sproule and accepted without any further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.
- Estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

All of the reserves held by Manitok as at December 31, 2013 are located in Canada and, specifically, in the province of Alberta.

Reserves Data (Forecast Prices and Costs)

The following table summarizes Sproule's estimates of Manitok's oil and natural gas reserves at December 31, 2013, using the Sproule Price Forecast.

SUMMARY OF OIL AND GAS RESERVES AS AT DECEMBER 31, 2013
(Forecast Prices and Costs)

	LIGHT AND MEDIUM CRUDE OIL		NATURAL GAS[1]		NGLs		TOTAL	
RESERVES CATEGORY	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED								
Developed Producing	2,131.8	1,419.8	21,197	17,574	137.0	87.6	5,801.5	4,436.5
Developed Non-Producing	57.0	47.4	7,904	6,404	10.5	6.4	1,384.9	1,121.1
Undeveloped	1,623.9	1,103.4	3,616	2,947	44.0	31.1	2,270.6	1,625.7
TOTAL PROVED	**3,812.7**	**2,570.7**	**32,717**	**26,925**	**191.5**	**125.1**	**9,457.0**	**7,183.3**
PROBABLE	3,729.2	2,488.7	20,109	16,739	181.8	122.4	7,262.5	5,400.9
PROVED PLUS PROBABLE	**7,541.9**	**5,059.4**	**52,826**	**43,664**	**373.3**	**247.5**	**16,719.5**	**12,584.2**

(1) Estimates of reserves of natural gas include both associated and non-associated gas.

The following table is a summary of the net present values of future net revenues associated with such reserves at December 31, 2013, using the Sproule Price Forecast, before and after deducting income taxes, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%. Future net revenue includes estimated future abandonment costs related to wells and production facilities required to produce the reserves.

NET PRESENT VALUES OF FUTURE NET REVENUE[1] AS AT DECEMBER 31, 2013
(Forecast Prices And Costs)

	Before Income Taxes Discounted at (%/year)					**After Income Taxes Discounted at (%/year)**					**Unit Value Before Income Tax Discounted at 10%**
RESERVES CATEGORY	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	($/boe)
PROVED											
Developed Producing	164,903	140,417	123,873	111,932	102,879	147,039	125,636	111,253	100,900	93,058	27.92
Developed Non-Producing	17,966	13,754	11,015	9,126	7,759	13,497	10,269	8,170	6,720	5,670	9.82
Undeveloped	66,262	55,779	47,943	41,867	37,012	49,656	40,977	34,503	29,497	25,512	29.49
TOTAL PROVED	**249,131**	**209,949**	**182,831**	**162,925**	**147,651**	**210,191**	**176,881**	**153,926**	**137,118**	**124,239**	**25.45**
PROBABLE	212,723	154,874	121,601	99,965	84,666	160,234	115,334	89,578	72,835	60,994	22.52
PROVED PLUS PROBABLE	**461,853**	**364,823**	**304,432**	**262,890**	**232,317**	**370,425**	**292,216**	**243,503**	**209,952**	**185,233**	**24.19**

(1) Estimates of future net revenue, whether discounted or not, does not represent fair market value.

Components of Future Net Revenue

The following table sets out, in the aggregate, the various elements of the Corporation's future net revenue associated with the Corporation's reserves, calculated using the Sproule Price Forecast and without discount.

COMPONENTS OF FUTURE NET REVENUE[1] AS AT DECEMBER 31, 2013
(Forecast Prices And Costs) (Undiscounted)

RESERVES CATEGORY	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Development Costs (M$)**	**Well Abandonment and Other Costs (M$)[2]**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
TOTAL PROVED	546,881	142,124	119,724	30,717	5,186	**249,131**	38,940	**210,191**
PROVED PLUS PROBABLE	1,050,991	282,714	231,347	68,974	6,102	**461,853**	91,428	**370,425**

(1) Estimates of future net revenues whether discounted or not, does not represent fair market value.
(2) Excludes abandonment and reclamation costs for wells with no assigned reserves in the Sproule Evaluation, pipelines and associated processing and transport facilities.

Future Net Revenue by Production Group

The following table provides additional information derived from the Sproule Evaluation, by production group, regarding the future net revenues associated with the Corporation's reserves, before deducting income taxes and calculated using a 10% discount rate.

NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAXES BY PRODUCTION GROUP AS AT DECEMBER 31, 2013 (Forecast Prices And Costs) (10% discount rate)				
	LIGHT AND MEDIUM CRUDE OIL(2)		NATURAL GAS(2)	
RESERVES CATEGORY	(M$)	($/boe)	(M$)	($/boe)
TOTAL PROVED	**140,820**	**40.63**	**42,011**	**11.30**
PROVED PLUS PROBABLE	**251,118**	**37.47**	**53,314**	**9.06**

(1) Estimates of future net revenue, whether discounted or not, does not represent fair market value.
(2) Estimates of reserves include both associated and non-associated gas and by-products. The production groupings are determined based upon the primary product produced from each reserve entity. The values and volumes of associated gas and the by-products derived from such associated gas are included with oil. The values and volumes of the by-products derived from non-associated gas are included with natural gas.
(3) Unit amounts are derived using net reserves volumes.
(4) Future net revenue is after deduction of estimated costs of abandonment of existing and future wells.

Pricing Assumptions

Forecast Prices Used in Estimates

The following table sets out the Sproule Price Forecast used for the Sproule Evaluation. The pricing and cost assumptions used were determined by Sproule using information available from numerous government agencies, industry publications, oil refineries, natural gas marketers and industry trends. These forecast price assumptions are subject to many uncertainties that exist in both the domestic and international petroleum industries.

SPROULE PRICE FORECAST AS AT DECEMBER 31, 2013							
	CRUDE OIL			NATURAL GAS	NGLs		
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($/bbl)	Cromer Medium 35° API ($/bbl)	Alberta AECO-C Spot ($/mmbtu)	Edmonton Butane ($/bbl)	Edmonton Pentanes Plus ($/bbl)	Exchange Rate ($US/$CAD)
2014	94.65	92.64	90.64	4.00	69.05	103.50	0.940
2015	88.37	89.31	87.31	3.99	66.57	99.78	0.940
2016	84.25	89.63	87.63	4.00	66.81	100.14	0.940
2017	95.52	101.62	99.62	4.93	75.74	113.53	0.940
2018	96.96	103.14	101.14	5.01	76.88	115.24	0.940
2019	98.41	104.69	102.69	5.09	78.03	116.97	0.940
2020	99.89	106.26	104.26	5.18	79.20	118.72	0.940
2021	101.38	107.86	105.86	5.26	80.39	120.50	0.940
2022	102.91	109.47	107.47	5.35	81.60	122.31	0.940
2023	104.45	111.12	109.12	5.43	82.82	124.14	0.940
2024	106.02	112.78	110.78	5.52	84.06	126.01	0.940
thereafter	Escalate at 1.5% per annum						

The actual weighted average commodity prices received by Manitok in 2013 are as follows: (a) light crude oil: $89.75/bbl; (b) natural gas: $3.61/mcf; and (c) NGLs: $78.07/bbl.

Reconciliation of Changes in Reserves

The following tables set forth a reconciliation of the Corporation's gross reserves using the Sproule Price Forecast for the year ended December 31, 2013 as derived from the Sproule Evaluation against the Sproule evaluation of such reserves for the year ended December 31, 2012, using the Sproule price forecast provided in the Sproule evaluation for the year ended December 31, 2012.

	Light and Medium Crude Oil			**NGLs**		
Factors	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**
December 31, 2012	2,738.1	2,530.1	5,268.2	231.7	189.2	420.9
Extensions(1)	57.4	208.1	265.5	0.2	1.0	1.2
Infill drilling(2)	1,820.2	2,013.4	3,833.6	5.1	5.9	11.0
Improved recovery	-	-	-	-	-	-
Technical revisions(3)	(59.4)	(1,019.6)	(1,079.0)	(13.6)	(13.3)	(26.9)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors(4)	10.2	(2.8)	7.4	(1.2)	(1.1)	(2.3)
Production(5)	(753.8)	-	(753.8)	(30.6)	-	(30.6)
December 31, 2013	**3,812.7**	**3,729.2**	**7,541.9**	**191.6**	**181.7**	**373.3**

	Natural Gas			**Total**		
Factors	**Gross Proved (Mmcf)**	**Gross Probable (Mmcf)**	**Gross Proved Plus Probable (Mmcf)**	**Gross Proved (Mboe)**	**Gross Probable (Mboe)**	**Gross Proved Plus Probable (Mboe)**
December 31, 2012	30,358	24,681	55,039	8,029.5	6,832.8	14,862.3
Extensions(1)	103	375	478	74.8	271.5	346.3
Infill drilling(2)	1,814	2,064	3,879	2,127.7	2,363.4	4,491.0
Improved recovery	-	-	-	-	-	-
Technical revisions(3)	5,000	(6,958)	(1,959)	760.1	(2,192.4)	(1,432.3)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors(4)	(258)	(53)	(311)	(34.0)	(12.8)	(46.7)
Production(5)	(4,300)	-	(4,300)	(1,501.1)	-	(1,501.1)
December 31, 2013	**32,717**	**20,109**	**52,826**	**9,457.0**	**7,262.5**	**16,719.5**

(1) The majority of reserve changes comprising "Extensions" were the result of drilling activities in the Stolberg area of Alberta. Wells were drilled extending the play beyond lands to which reserves had previously been attributed. As a result of these successful wells, reserves were attributed to future well locations proximal to this well.

(2) The majority of reserve changes comprising "Infill drilling" were the result of drilling activities in the Stolberg area of Alberta. Infill wells are a result of drilling within an established producing area that results in increased recovery or favourable economics.

(3) "Technical Revision" resulted from category changes and the removal of four high risk wells in the probable category.

(4) "Economic Factors" although not significant, result from natural gas prices forecast by Sproule that were lower than the natural gas forecast used in the 2012 Sproule evaluation, resulting in negative impacts on some reserve volumes.

(5) Represents production for 2013.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table sets forth the volumes of each of the gross proved undeveloped reserves and the gross probable undeveloped reserves from the Sproule Evaluation for each product type booked as reserves in each of the most recent three financial years based on the Sproule Price Forecast.

2013 UNDEVELOPED RESERVES								
	PROVED UNDEVELOPED RESERVES				PROBABLE UNDEVELOPED RESERVES			
Year	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas (Mmcf)	NGLs (Mbbls)	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas (Mmcf)	NGLs (Mbbls)
Dec. 2013	**1,624**	**-**	**3,616**	**44**	**2,655**	**-**	**10,945**	**126**
Dec. 2012	1,674	-	5,394	53	1,939	-	17,711	139
Dec. 2011	60	142	2,561	26	1,312	149	9,674	29

Manitok has a conservative list of low-risk opportunities within the Sproule Evaluation. A total of 25 gross (15.9 net) locations have been identified in the Sproule Evaluation, comprising 41% of the total booked proved plus probable reserves, as compared to 24 gross (14.6 net) locations in the 2012 Sproule evaluation, suggesting a continued conservative approach to booking undeveloped locations. A total of 15 gross (9.5 net) locations have been identified in the Cordel/Stolberg area, with the remaining 10 gross (6.4 net) well locations identified as liquids-rich natural gas in the Fallen Timber, Cabin Creek and Banshee areas and Cardium oil in the Quirk Creek area. The future development costs are approximately 1.3 times projected 2014 undiscounted proved plus probable before tax cash flow.

The highest value undeveloped reserves occur in the Cordel/Stolberg area. On a before tax NPV10% valuation basis, the proved plus probable undeveloped value in the Cordel/Stolberg area is 40% of the total proved plus probable reserve value. The Corporation also added a relatively small volume of probable oil reserves (237 Mboe) attributable to a waterflood pilot in the Cordel Cardium oil pool, which was based on a third party reservoir engineering study accepted by Sproule. The waterflood pilot is expected to commence in 2014, subject to further technical review.

Manitok's plan relating to the development of its proved and probable undeveloped reserves and the timing of such reserves development may change based on commodity prices or any changes in geological, geophysical, or engineering data that become available to Manitok. Capital allocation also depends upon an array of other potential investments in its areas of interest and other areas

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting P&NG prices and costs change. The reserve estimates contained herein are based on Sproule's production forecasts, prices and economic conditions at the time of preparation of the Sproule Evaluation. The factors and assumptions that affect these reserve estimates include, among other things: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions are often required over time due to changes in well performance, prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end P&NG prices and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The following table sets forth the future development costs that have been deducted in the estimation of future net revenue attributable to the Corporation's reserves estimated in the Sproule Evaluation using the Sproule Price Forecast and calculated without discount.

FUTURE DEVELOPMENT COSTS
(Forecast Prices and Costs)

Calendar Year	Total Proved (M$)	Proved Plus Probable (M$)
2014	25,848	59,599
2015	4,842	5,940
2016	26	26
2017	-	-
2018	-	-
Thereafter	-	3,409
Total Undiscounted	**30,717**	**68,974**

The Corporation expects to be able to fund the development costs required in the future from working capital, internally generated funds from operations, existing credit facilities and access to equity markets. Interest and other costs of external funding are not included in the future net revenue estimates. The Corporation does not expect any inordinate costs to be associated with such funding sources.

There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the Sproule Evaluation. Failure to develop those reserves would have a negative impact on future production and funds from operations.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The Corporation's important properties and facilities are described under the heading "*Description of the Business – Principal Properties*".

Producing and Non-Producing Wells

The following table shows Manitok's producing and non-producing P&NG wells at December 31, 2013, all of which are in Alberta.

2013 PRODUCING AND NON-PRODUCING WELLS								
	CRUDE OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-producing		Producing		Non-producing	
Area	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	26	13.0	7	3.8	52	15.5	54	21.8

Properties with No Attributed Reserves

At December 31, 2013 Manitok held 375,793 (323,907 net) acres of undeveloped land, all of which is in Alberta. Approximately 5% of the net acres for the rights to explore, develop and exploit are expected to expire prior to the end of 2014. It is expected that the Corporation will be able to continue approximately 10% of this expiring acreage.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of Manitok's properties with no attributed reserves. Manitok will be required to make substantial capital expenditures in order to prove, exploit, develop and produce P&NG from these properties in the future. If Manitok's funds from operations are not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause Manitok to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of Manitok to access sufficient capital for its exploration and development activities could have a material adverse effect on Manitok's ability to execute its business strategy to develop these prospects. See "*Risk Factors – Access to Credit Markets*".

The significant economic factors that affect Manitok's development of its lands to which no reserves have been attributed are future commodity prices for P&NG and Manitok's outlook relating to such prices, and the future costs of drilling, completing, equipping, tie-in and operating the wells at the time that such activities are considered in the future.

The significant uncertainties that affect Manitok's development of such lands are: (i) the future drilling and completion results Manitok achieves in its development activities; (ii) drilling and completion results achieved by others on lands in proximity to Manitok's lands; and (iii) future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Alternatively, uncertainty as to the timing and nature of the evolution or development of better exploration drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such lands.

Forward Contracts and Marketing

With the exception of the following financial derivative contracts entered into pursuant to the Corporation's risk management program, as of December 31, 2013, the Corporation does not have any material commitments to buy or sell P&NG production.

As at December 31, 2013, the Corporation held the following derivative commodity contracts:

Product	**Notional quantity**	**Term**	**Reference**	**Strike Price**	**Type of Contract**
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$96.00	Swap
Oil	500 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$93.35	Swap
Oil	300 bbls/d	January 1, 2014 to December 31, 2014	CAD$ WTI	$94.00	Swap
Oil	1.000 bbls/d	January 1, 2015 to December 31, 2015	CAD$ WTI	$95.00	Swap
Oil	500 bbls/d	January 1, 2015 to December 31, 2015	CAD$ WTI	$91.00	Swap
Natural gas	5,000 GJ/d	January 1, 2014 to December 31, 2014	CAD$ AECO	$3.35	Put option(1)
Natural gas	5,000 GJ/d	January 1, 2014 to December 31, 2014	CAD$ AECO	$3.75	Put option(1)
Oil	500 bbls/d	January 1, 2015 to December 31, 2015	CAD$ WTI	$96.00	Swaption(2)
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CAD$ WTI	$95.00	Swaption(3)
Oil	500 bbls/d	January 1, 2016 to December 31, 2016	CAD$ WTI	$91.00	Swaption(4)

(1) The counter-party to this contract receives a deferred put option premium of $0.35/GJ.
(2) The counter-party to this contract holds a one-time option no later than December 31, 2014 to extend a swap on 500 bbls/d of oil at CAD$96.00 for the period indicated.
(3) The counter-party to this contract holds a one-time option no later than December 31, 2015 to extend a swap on 1,000 bbls/d of oil at CAD$95.00 for the period indicated.
(4) The counter-party to this contract holds a one-time option no later than December 31, 2015 to extend a swap on 500 bbls/d of oil at CAD$91.00 for the period indicated.

Subsequent to December 31, 2013, the Corporation has entered into the following derivative financial instrument:

Product	**Notional quantity**	**Term**	**Reference**	**Strike Price**	**Type of Contract**
Natural gas	5,000 GJ/d	January 1, 2015 to December 31, 2015	CAD$ AECO	$3.73	Put option(1)

(1) The counter-party to this contract receives a deferred put option premium of $0.33/GJ.

As at December 31, 2013, the Corporation held the following physical sales contracts:

Product	**Volume**	**Term**	**Strike Price**	**Type of Contract**
Natural gas	2,000 GJ/d	April 1, 2014 to October 31, 2014	$3.66	AECO fixed price

Subsequent to December 31, 2013, the Corporation has entered into the following physical sales contracts:

Product	**Volume**	**Term(1)**	**Strike Price**	**Type of Contract**
Natural gas	4,000 GJ/d	April 1, 2014 to October 31, 2014	$3.82	AECO fixed price
Natural gas	5,000 GJ/d	March 1, 2014 to March 31, 2014	$5.10	AECO fixed price

(1) Transactions with common terms have been aggregated and presented as the weighted average price.

Additional Information Concerning Abandonment and Reclamation Costs

The Sproule Evaluation has included estimated well abandonment costs for only the wells with assigned reserves and future drilling locations identified in the Sproule Evaluation, but reclamation costs have not been included.

Manitok currently has 54.1 net wells that ultimately will need to be abandoned and/or reclaimed.

The following table sets forth the total amount of future costs in the Sproule Evaluation in connection with the abandonment of wells in the proved and probable category.

FUTURE ABANDONMENT AND RECLAMATION COSTS RELATING TO PROVED PLUS PROBABLE RESERVES (Forecast Pricing and Costs)		
	Undiscounted Amount (M$)	**Discounted Amount at 10% per year (M$)**
Total amount of the future abandonment costs	3,161	546
Anticipated to be paid in 2014[(1)]	25	23
Anticipated to be paid in 2015[(1)]	16	13
Anticipated to be paid in 2016[(1)]	13	10
Total anticipated costs in the next three years	54	46

(1) Excludes abandonment and reclamation costs for wells with no assigned reserves in the Sproule Evaluation, pipelines and associated processing and transport facilities.

Tax Horizon

Based on after-tax economic forecasts in the Sproule Evaluation, income taxes are payable by the Corporation in 2014, using total proved plus probable reserves.

Costs Incurred

The following table sets forth Manitok's property acquisition costs for proved properties and unproved properties, exploration costs and development costs for the year ended December 31, 2013.

2013 ACQUISITION, EXPLORATION AND DEVELOPMENT COSTS				
Acquisition Costs Proved Properties (M$)	**Acquisition Costs Unproved Properties (M$)**	**Exploration Costs (M$)**	**Development Costs (M$)**	**Total (M$)**
66	22,927	16,795	42,170	**81,958**

Exploration and Development Activities

Manitok's planned exploration and development activities are described in "*Description of the Business*". Manitok's most important exploration and development activities will focus on the drilling and completion of light oil wells in the Alberta foothills and southeast Alberta.

The following table sets forth a summary of Manitok's exploration and development drilling activities as defined in the Tax Act for the year ended December 31, 2013.

2013 EXPLORATION AND DEVELOPMENT ACTIVITIES						
	EXPLORATION WELLS		DEVELOPMENT WELLS		TOTAL	
Type	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells	7.0	3.9	7.0	4.6	14.0	8.5
Natural Gas Wells	-	-	1.0	0.8	1.0	0.8
Service Wells	-	-	-	-	-	-
Stratigraphic Test Wells	-	-	-	-	-	-
Dry Holes(1)	-	-	1.0	0.5	1.0	0.5
Total	**7.0**	**3.9**	**9.0**	**5.9**	**16.0**	**9.8**

(1) Relates to a well drilled in the Cabin Creek area of Alberta that did not result in economic quantities of proved reserves.

Production Estimates

The following table sets forth Sproule's forecast volumes of Manitok's production from gross proved reserves and gross probable reserves as estimated in the Sproule Evaluation for the 2014 financial year.

2014 PRODUCTION VOLUME ESTIMATES				
Reserves Category	**Light and Medium Crude Oil (Mbbls)**	**Natural Gas (Mmcf)**	**NGLs (Mbbls)**	**Total (Mboe)**
Gross Total Proved	1,343	6,217	28	2,407
Gross Probable	370	840	6	516

The estimated production volumes for the area that accounts for more than 20% of Sproule's total forecast production for the year ended December 31, 2013 is set forth below:

2014 PRODUCTION VOLUMES FOR KEY FIELD		
Area Name	**2014 Sproule Forecast Production for determining Gross Total Proved Reserves (Mboe)**	**2014 Sproule Forecast Production for determining Gross Probable Reserves (Mboe)**
Cordel / Stolberg	1,920	422

Production History

Average Daily Production by Product Type

The following table sets out, by product type, Manitok's average gross daily production volumes for each quarter of the year ended December 31, 2013.

2013 QUARTERLY PRODUCTION HISTORY					
	Three months ended				**Year ended**
Product Type	**March 31, 2013**	**June 30, 2013**	**September 30, 2013**	**December 31, 2013**	**December 31, 2013**
Light and Medium Crude Oil (bbl/d)(1)	2,053	2,666	2,541	3,690	2,741
Natural Gas (mcfe/d)(2)	9,200	8,277	7,664	7,794	8,229
Total (boe/d)	**3,586**	**4,045**	**3,819**	**4,989**	**4,113**

(1) Includes solution gas and associated by-products.
(2) Includes associated by-products.

Realized Price, Royalty, Operating, Transportation and Marketing Expenses and Operating Netbacks

The following tables set forth, by product type, Manitok's share of average daily production before deduction of royalties, the prices received, royalties paid, production costs incurred and the resulting operating netback on a per unit of volume basis, for each quarter of the year ended December 31, 2013.

LIGHT AND MEDIUM CRUDE OIL 2013 QUARTERLY PRICE, ROYALTY, OPERATING, TRANSPORTAION AND MARKIETING EXPENSES AND NETBACK HISTORY					
	Three months ended				**Year ended**
$/bbl	**March 31, 2013**	**June 30, 2013**	**September 30, 2013**	**December 31, 2013**	**December 31, 2013**
Realized Price(1)(2)	78.24	73.90	76.75	67.89	73.33
Royalty expenses	(25.24)	(20.90)	(24.39)	(13.44)	(19.99)
Operating expenses, net of recoveries	(7.89)	(5.48)	(7.54)	(8.78)	(7.53)
Transportation and marketing expenses	(3.88)	(3.75)	(3.25)	(3.64)	(3.62)
Operating Netback	41.23	43.77	41.57	42.03	42.19
Royalty Income	-	-	-	-	-
Operating Netback including Royalty Income	**41.23**	**43.77**	**41.57**	**42.03**	**42.19**

(1) Does not include royalty income
(2) Includes solution gas and associated by-products

NATURAL GAS 2013 QUARTERLY PRICE, ROYALTY, OPERATING, TRANSPORATION AND MARKETING EXPENSES AND NETBACK HISTORY					
	Three months ended				**Year ended**
$/mcfe	**March 31, 2013**	**June 30, 2013**	**September 30, 2013**	**December 31, 2013**	**December 31, 2013**
Realized Price(1)(2)	4.13	4.37	3.23	4.48	4.06
Royalty Expenses	(0.65)	0.28	(0.16)	(0.15)	(0.18)
Operating expenses, net of recoveries	(1.80)	(1.37)	(0.42)	(1.50)	(1.30)
Transportation and marketing expenses	(0.22)	(0.22)	(0.20)	(0.26)	(0.23)
Operating Netback	1.46	3.06	2.45	2.57	2.35
Royalty Income	0.17	0.30	0.01	-	0.13
Operating Netback including Royalty Income	**1.63**	**3.36**	**2.46**	**2.57**	**2.48**

(1) Does not include royalty income.
(2) Includes associated by-products

2013 Production History

The following table sets forth Manitok's annual production volumes for the year ended December 31, 2013 by product type, for the fields comprising more than 20% of Manitok's total production and in total.

2013 PRODUCTION VOLUMES BY PRODUCT TYPE FOR MAJOR FIELDS				
Area name	**Light and Medium Crude Oil (Mbbls)**	**Natural Gas (Mmcf)**	**NGLs (Mbbls)**	**Total (Mboe)**
Cordel / Stolberg	750.2	2,277.5	11.1	1,140.9

DIVIDEND AND DISTRIBUTION POLICY

The Corporation's credit facilities may restrict its ability to pay dividends, and thus the Corporation's ability to pay dividends on the Manitok Shares will depend on, among other things, the Corporation's level of indebtedness at the time of the proposed dividend and whether it is in compliance with such facilities. The Corporation has never paid any dividends on Manitok Shares or made distributions to shareholders and it is unlikely to pay any dividends on Manitok Shares or make distributions to shareholders in the foreseeable future.

CAPITAL STRUCTURE

The authorized capital of the Corporation consists of an unlimited number of Manitok Shares and an unlimited number of preferred shares ("**Preferred Shares**") issuable in series, each without par value. At April 23, 2014, there were 71,122,006 Manitok Shares outstanding and there were no Preferred Shares outstanding. The material characteristics of each class of authorized shares are set forth below.

Manitok Shares

Holders of Manitok Shares are entitled to: (a) receive notice of and attend and vote at all meetings of shareholders of the Corporation, except meetings at which only holders of a specified class of shares are entitled to vote; (b) receive any dividends declared by the Corporation on the Manitok Shares, provided that the Corporation is not entitled to declare dividends on the Preferred Shares, or on any of such classes of shares without being obliged to declare any dividends on the Manitok Shares; (c) subject to the rights, privileges, restrictions and conditions attaching to any other class of shares of the Corporation, to receive the remaining property of the Corporation upon dissolution in equal rank with the holders of all other Manitok Shares; and (d) the rights, privileges and restrictions normally attached to Manitok Shares.

Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each consisting of a number of Preferred Shares as determined by the Board, which also may fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. The holders of Preferred Shares are entitled to dividends, if, as and when declared by the Board. However, the Board may declare a dividend on any class of shares of the Corporation without being obligated to declare a dividend on the Preferred Shares. The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets in the event of voluntary or involuntary liquidation, dissolution or winding-up of the Corporation or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, rank on a parity with the Preferred Shares of every other series and shall be entitled to preference over Manitok Shares and the shares of any other class ranking junior to the Preferred Shares.

MARKET FOR SECURITIES

The Manitok Shares are listed for trading on TSX-V under the trading symbol "MEI". The following table sets forth the price ranges and volumes of Manitok Shares that were traded on TSX-V during the year ended December 31, 2013.

Month	High	Low	Monthly Trading Volume
January	3.49	2.87	11,630,070
February	3.27	2.35	12,309,109
March	2.86	2.59	5,421,055
April	2.93	2.43	7,807,466
May	2.86	2.49	3,672,367
June	3.14	2.79	4,190,491
July	3.05	2.21	9,635,745
August	2.92	2.55	4,392,978
September	3.06	2.79	4,355,774
October	3.38	2.52	10,349,363
November	2.84	2.14	7,799,611
December	2.27	1.93	9,342,438

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Companies operating in the oil and natural gas industry are subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry. It is not expected that any of such controls or regulations would affect the operations of the Corporation in a manner materially different than they would affect other companies of similar size in the oil and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western 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 (the "**Prosperity Act**"). 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

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also 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 also 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 must 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 ("**U.S.**") 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.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGLs, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold 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. 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 royalties, gross overriding royalties, net profits interests or net carried interests.

Occasionally, the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and funds from operations within the industry.

Alberta

Producers of P&NG from Crown lands in Alberta are required to make annual rental payments, currently at a rate of $3.50 per hectare, and monthly royalty payments in respect of P&NG produced.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which were subsequently implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system that were intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors. As a result of this announcement, the maximum royalty rates for conventional P&NG production were decreased as of the January 2011 production month and certain temporary incentive programs were made permanent.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure, which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF range from 0% to 50%, an increase from the previous maximum rates of 30% to 35% depending on the vintage of the oil, and rate caps are set at $120.00/bbl. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 40%.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5% to 50%, an increase from the previous maximum rates of 5% to 35%, and rate caps are set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF were reduced to 36%.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of oil: rates are 1% when the market price of oil is less than or equal to $55.00/bbl and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120.00/bbl or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% to 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55.00/bbl up to 40% when oil is priced at $120.00/bbl or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost P&NG reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional oil wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional P&NG wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 bbls of oil or 500 Mmcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

On May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 Mmcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 Mmcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal

- distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice if it decides to discontinue the program.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal natural gas wells and a royalty exemption for re-entry wells, among others.

Land Tenure

Crude oil and natural gas located in the western Canadian provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce P&NG pursuant to leases, licences, and permits for varying terms from two years and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such P&NG are granted by lease on such terms and conditions as may be negotiated.

The province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and indicated that the decision would be revisited in the spring of 2012. This decision was to be revisited in spring 2012 and the formal response from Alberta Energy was communicated to industry in April 2013 when the issuance of shallow rights reversion notices was indefinitely suspended for agreements made prior to 2009. Leases issued after 2009 remain subject to the shallow rights reversion policy.

Environmental Regulation

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.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the Public Lands Act. On March 29, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act and the Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force on April 1, 2014.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Climate Change Regulation

Federal

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 ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG 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 set forth a plan for regulations to address both GHGs 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 Government of Canada indicates that it is taking a sector-by-sector regulatory approach to reducing GHG 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 GHG 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 GHG emissions.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established

Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

ESCROWED SECURITIES

To the knowledge of the Corporation, there are no securities of the Corporation that are held in escrow as at the date hereof.

DIRECTORS AND OFFICERS

Directors

The directors of the Corporation are elected annually at the annual meeting of shareholders. The following table sets forth the name, province and country of residence, year first elected to the Board and principal occupation during the past five years or more:

Name, Province and Country of Residence	**Director Since**	**Present Occupations and Positions Held During the Past Five Years or More**
Bruno P. Geremia(1)(2)(3) *Alberta, Canada* Chairman of the Board	July 8, 2010	Mr. B. Geremia is chairman of the board of Manitok, chairman of the Audit Committee and a member of the Compensation Committee and Reserves and Occupational Health and Safety Committee. He has been the Vice-President and Chief Financial Officer of Birchcliff Energy Ltd., a TSX listed oil and gas company, from October 2004 to present. Mr. B. Geremia was chairman of the board of MEX from April 20, 2005 to July 8, 2010.
Robert J. (Bob) Dales(1)(3) *Alberta, Canada* Independent Director	July 8, 2010	Mr. Dales is a director of Manitok and is a member of the Audit Committee and Reserves and Occupational Health and Safety Committee. He has been President of Valhalla Ventures Inc., a private investment corporation, since January 1999.
Wilfred A. (Wilf) Gobert(1)(2) *Alberta, Canada* Independent Director	July 8, 2010	Mr. Gobert is a director of Manitok and is chairman of the Compensation Committee and a member of the Audit Committee. He has been an independent businessman since May 2006 and prior thereto, he was Managing Director, Research of Peters & Co. Limited, an investment dealer, from August 1979 to September 2002. Mr. Gobert was a director of MEX from February 28, 2007 to July 8, 2010.
Gregory E. (Greg) Peterson(2) *Alberta, Canada* Independent Director and Corporate Secretary	July 8, 2010	Mr. Peterson is a director and Corporate Secretary of Manitok and is a member of the Compensation Committee. He has been a Partner with Gowling Lafleur Henderson LLP, a national Canadian law firm, since 1990. Mr Peterson was a director and Corporate Secretary of MEX from April 20, 2005 to July 8, 2010.
Tom Spoletini(1)(2)(3) *Alberta, Canada* Independent Director	July 8, 2010	Mr. Spoletini is a director of Manitok and is a member of the Audit Committee, Compensation Committee and Reserves and Occupational Health and Safety Committee. He was a founding partner and the President of Spolumbo's Deli, a private company based out of Calgary, Alberta since 1991, and the President and Chief Executive Officer of Rosa Capital Inc., a capital pool company listed on the TSX-V, since October 2010. Mr. Spoletini was a director of MEX from April 20, 2005 to July 8, 2010.
Massimo M. (Mass) Geremia(1)(3) *Alberta, Canada* Director	July 8, 2010	See Mr. M. Geremia's biography under *"Executive Officers"*.
Cameron G. (Cam) Vouri(3) *Alberta, Canada* Director	July 8, 2010	See Mr. C. Vouri's biography under *"Executive Officers"*.

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Reserves and Occupational Health and Safety Committee.
(4) Each director's term expires at the close of the next annual meeting of the shareholders of the Corporation, unless re-elected.

The Board has an Audit Committee, a Compensation Committee and a Reserves and Occupational Health and Safety Committee. The Audit Committee is comprised of Messrs. Bruno P. Geremia (chair), Robert J. Dales, Wilfred A. Gobert, Tom Spoletini and Massimo M. Geremia. The Compensation Committee is comprised of Messrs. Wilfred A. Gobert (chair), Bruno P. Geremia, Gregory E. Peterson and Tom Spoletini. The Reserves and Occupational Health and Safety Committee is comprised of Messrs. Cameron G.Vouri (chair), Robert J. Dales, Bruno P. Geremia, Tom Spoletini and Massimo M. Geremia. All of the members of such committees, and all of the members of the Board, are independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**"), other than Mr. M. Geremia and Mr. Vouri, as officers of the Corporation, and Mr. B. Geremia, as an immediate family member of an officer of the Corporation. Due to the small size of the Board, the Corporation does not have a separate corporate governance or executive committee.

Executive Officers

The following table sets forth the name, province and country of residence, position with the Corporation, and principal occupation during the past five years or more and educational background of each of the executive officers of the Corporation.

Name, Province and Country of Residence	Current Position with Manitok	Principal Occupations During the Past Five Years or More and Educational Qualifications
Massimo M. (Mass) Geremia *Alberta, Canada*	President and Chief Executive Officer	Mr. M. Geremia is the President and Chief Executive Officer and a director of Manitok. He co-founded MEX on April 20, 2005 and served as the President, Chief Executive Officer and Chief Financial Officer from April 20, 2005 to July 8, 2010. Prior thereto, Mr. M. Geremia was a manager of Birchcliff Energy Ltd., a TSX listed oil and gas company, from April 2005 to May 2008.
Cameron G. (Cam) Vouri *Alberta, Canada*	Chief Operating Officer	Mr. Vouri was appointed the Chief Operating Officer in October 2013, is a director of Manitok and the chairman of the Reserves and Occupational Health and Safety Committee and is a professional engineer. Prior thereto, he had been an independent businessman from March 2011 to September 2013, Vice President, Operations and Chief Operating Officer of Renegade Petroleum Ltd., a TSX-V listed oil and gas company, from September 2010 to February 2011 and President, Canadian Oil and Gas Division of Provident Energy Trust from May 2000 to April 2010. Mr. Vouri was a director of MEX from February 1, 2007 to July 8, 2010.
Robert G. (Rob) Dion *Alberta, Canada*	Vice-President, Finance and Chief Financial Officer	Mr. Dion is Vice-President, Finance and Chief Financial Officer and is a chartered accountant. He was Controller of MEX from April 16, 2010 until July 8, 2010. Prior thereto, Mr. Dion was Finance Manager at Compton Petroleum Corporation from September 2003 to January 2010.
Donald (Don) Martin *Alberta, Canada*	Vice-President, Exploration - Plains	Mr. Martin is Vice-President, Exploration – Plains and is a professional geologist. Prior thereto, he was Vice President, Exploration for Alston Energy Inc., a TSX-V listed oil and gas company, from June 2011 to September 2013 and a founding member of TriWestern Energy Corp, a private oil and gas company from October 2009 to June 2011.
Yvonne McLeod[(1)] *Alberta, Canada*	Vice-President, Drilling and Facilities	Ms. McLeod is Vice-President, Drilling, Completions and Facilities and is a professional engineer. Prior thereto, Ms. McLeod was a senior drilling engineer at Talisman Energy Inc. from 2004 to February 2012.

(1) Effective March 20, 2014, Ms. McLeod was no longer employed with the Corporation.

Shareholdings of Directors and Executive Officers

At December 31, 2013, the directors and executive officers of the Corporation, as a group, beneficially owned, or exercised control or direction over, directly or indirectly, 4,558,050 Manitok Shares, representing approximately 6.1% of the 74,492,340 Manitok Shares issued and outstanding at that date. The directors and executive officers, as a group, also held options to purchase 2,355,000 Manitok Shares at December 31, 2013.

The fully diluted holdings of directors and executive officers, as a group, were 6,913,050 Manitok Shares, or approximately 8.6% of the 80,099,780 Manitok Shares that were outstanding on a fully diluted basis, at December 31, 2013.

Orders

To the knowledge of management of the Corporation, other than as disclosed herein, no director or executive officer as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Corporation), that (a) was subject to 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 (b) 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. For the purposes hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days.

Bankruptcies

To the knowledge of management of the Corporation, other than as disclosed herein, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control thereof, (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any company (including the Corporation) 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, or (b) has, within the 10 years before the date hereof, 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.

Penalties and Sanctions

To the knowledge of management of the Corporation, no director or executive officer or shareholder holding a sufficient number of Manitok Shares to affect materially the control of the Corporation, 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 has been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject to in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial or director positions with other P&NG companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation. The table below lists those directors of the Corporation that are also directors of other P&NG companies and sets forth certain details of those directorships.

Name	Name of Reporting Issuer	Exchange	Term
Massimo M. Geremia	Amarok Energy Inc. Rosa Capital Inc.	TSX-V TSX-V	August 2012 – Present October 2012 – Present
Robert J. Dales	Amarok Energy Inc. Arcan Resources Inc. Kelt Exploration Ltd.	TSX-V TSX-V TSX	January 2010 – Present January 2007 – Present October 2012 – Present
Wilfred A. Gobert	Canadian Natural Resources Limited Catapult Energy 2011 LP Gluskin Sheff + Associates Trilogy Energy Inc.	TSX and New York Stock Exchange TSX TSX TSX	November 2010 – Present August 2008 – Present May 2006 – Present November 2006 – Present
Gregory E. Peterson	Great Prairie Energy Services Inc. Rosa Capital Inc.	TSX-V TSX-V	February 2011 – Present February 2011 – Present

AUDIT COMMITTEE

Audit Committee

The Board has established the Audit Committee. The Audit Committee reviews, along with management and the external auditors, any significant financial reporting issues, the financial statements of the Corporation and any other matters of relevance to the parties. The Audit Committee meets quarterly to review and approve the interim financial statements and management's discussion and analysis ("**MD&A**") of the Corporation prior to their release, as well as annually to review the Corporation's annual audited financial statements and MD&A and to recommend their approval to the Board. The external auditors have unrestricted access to the Audit Committee.

The Corporation is relying upon the exemption in section 6.1 of NI 52-110 as the Corporation, as a venture issuer within the meaning ascribed thereto in NI 52-110, is exempt from the requirements of Part 3 (*Composition of the Audit Committee*) and Part 5 (*Reporting Obligations*) of NI 52-110.

Disclosure of the Audit Committee practices is set forth below.

Audit Committee Charter

In response to NI 52-110, the Corporation has established an Audit Committee charter to address certain matters, which include but are not limited to the following: (a) the procedure to nominate the external auditor and the recommendation of its compensation; (b) the overview of the external auditor's work; (c) pre-approval of non-audit services; (d) the review of financial statements, MD&A and financial sections of other public reports requiring board approval; (e) the procedure to respond to complaints respecting accounting, internal accounting controls or auditing matters and the procedure for confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters; and (f) the review of the Corporation's hiring policies towards present or former employees or partners of the Corporation's present or former external auditor.

The full text of the Audit Committee charter is attached hereto as Schedule "A".

Composition of the Audit Committee

The Audit Committee is comprised of Mr. Bruno P. Geremia (Chair), Mr. Robert J. Dales, Mr. Wilfred A. Gobert, Mr. Tom Spoletini and Mr. Massimo M. Geremia. Each member of the Audit Committee is independent within the meaning of section 1.4 of NI 52-110, other than Mr. Massimo M. Geremia, as an officer of the Corporation, and Mr. Bruno P. Geremia, as an immediate family member of an officer of the Corporation. In addition, each member of the Audit Committee is financially literate within the meaning of section 1.6 of NI 52-110.

Relevant Education and Experience

Mr. Bruno P. Geremia is a Chartered Accountant and Chief Financial Officer of Birchcliff Energy Ltd., a TSX listed oil and gas company and the other four members of the Audit Committee have had long and successful business careers, having been the chief executive officer or chief operating officer of a substantial business enterprise or have been directors and members of the Audit Committee for several oil and natural gas exploration and production companies in the past. As a result, they are all “financially literate” in that they have an ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that can reasonably be expected to be raised by the Corporation’s financial statements. Details of the relevant experience of each of the members of the Audit Committee are set forth under the heading "*Directors and Officers – Directors*".

Audit Committee Oversight

No recommendation of the Audit Committee to nominate or compensate an external auditor was not adopted by the Board since the beginning of the Corporation's most recently completed financial year.

Reliance on Certain Exemptions

Since the commencement of the Corporation's most recently completed financial year, the Corporation has not relied on the exemptions contained in section 2.4 (*De Minimis Non-audit Services*) or Part 8 (*Exemptions*) of NI 52-110.

Pre-Approval Policies and Procedures

The Audit Committee has adopted policies and procedures for the engagement of non-audit services. The Audit Committee has delegated to its members the authority to pre-approve non-audit services, provided, however, that such pre-approval of non-audit services shall be presented to the Audit Committee at its first scheduled meeting following any such pre-approval.

External Auditor Service Fees

The table below summarizes the fees billed by the Corporation's external auditors, during the years ended December 31, 2013 and December 31, 2012. The Corporation changed auditors from Kenway Mack Slusarchuk Stewart LLP ("**KMSS**") to KPMG LLP ("**KPMG**") effective February 10, 2014. KPMG audited the Corporation's financial statements for the financial year ended December 31, 2013.

Nature of fees	2013	2012
Audit fees	\$65,000(1)	\$55,000(4)
Audit-related fees	\$22,500(2)	\$22,500(5)
Tax fees	-	-
All other fees	\$8,000(3)	\$10,000(6)
Total	**\$95,500**	**\$87,500**

(1) Fees paid to KMSS for the audit of annual financial statements for December 31, 2012.
(2) Fees paid to KMSS for the review of interim financial statements for March 31, 2013, June 30, 2013 and September 30, 2013.
(3) Fees paid to KMSS for the due diligence procedures for the November 2013 Financing.
(4) Fees paid to KMSS for the audit of annual financial statements for December 31, 2011.
(5) Fees paid to KMSS for the review of interim financial statements for March 31, 2012, June 30, 2012 and September 30, 2012.
(6) Fees paid to KMSS for the due diligence procedures for the October 2012 Financing.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

To the knowledge of the management of the Corporation, there are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated.

Regulatory Actions

To the knowledge of management of the Corporation, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the directors or executive officers of the Corporation, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of outstanding voting securities of the Corporation, nor any associate or affiliate of the foregoing persons had any material interest, direct or indirect, in any transaction during the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for Manitok Shares is Valiant Trust Company at its principal office located in Calgary, Alberta.

MATERIAL CONTRACTS

Other than the underwriting agreement dated effective as of October 25, 2013 in connection with the November 2013 Financing, the Corporation did not enter into any material contracts outside the ordinary course of business within the most recently completed financial year or prior thereto that are still in effect. See "*General Development of the Business – Three Year History*".

INTERESTS OF EXPERTS

The Sproule Evaluation was prepared by Sproule, an independently qualified reserves evaluator and auditor of Calgary, Alberta. As of the date hereof, the partners, employees and consultants of Sproule who participated in or who were in a position to directly influence the preparation of the Sproule Evaluation own no securities of the Corporation.

KPMG LLP have confirmed that they are independent of the Corporation within the meaning of the relevant rules and related interpretations relevant professional bodies in Canada and any applicable legislation or regulation.

ADDITIONAL INFORMATION

Additional information about the Corporation can be found on SEDAR at www.sedar.com and on the Corporation's website at www.manitokenergy.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Manitok Shares, and securities authorized for issuance under equity compensation plans, is contained in the Information Circular of the Corporation dated May 8, 2013. Additional financial information relating to the Corporation is provided in the Corporation's annual audited financial statements and MD&A for the year ended December 31, 2013.

SCHEDULE "A"
AUDIT COMMITTEE CHARTER

(Adopted by the Board of Directors on July 15, 2010)

A. PURPOSE

The overall purpose of the Audit Committee (the "**Committee**") of the Board of Directors (the "**Board**") is to assist the Board in fulfilling its oversight responsibilities and to carry out the functions associated with an audit committee of an issuer of the size and nature of Manitok Energy Inc. (the "**Corporation**"). The purpose of the Committee is to ensure that the Corporation's management has designed and implemented an effective system to review and report on the integrity of the financial statements of the Corporation. As part of this mandate, the Committee shall take all necessary steps so as to ensure compliance by the Corporation with all laws and regulatory policies, rules, regulations and instruments pertaining to audit and financial reporting that are applicable to the Corporation from time to time.

B. COMPOSITION, PROCEDURES AND ORGANIZATION

1. The Committee shall consist of not less than three members of the Board, each of whom:

   (a) must be "independent" ("independent" means that the audit committee has no direct or indirect material relationship with the Corporation, being a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a member's independent judgment (and certain individuals are deemed by Multilateral Instrument 52-110 to have a material relationship)); and

   (b) must be "financially literate" ("financially literate" means a member has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements);

   except as may be allowed under any applicable exemptions provided for under applicable laws or any exemption orders obtained from applicable regulatory authorities.

2. The Board, at its organizational meeting held in conjunction with each annual general meeting of the holders of shares of the Corporation, shall appoint the members of the Committee for the ensuing year. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

3. Unless the Board shall have appointed a chair of the Committee ("**Chairman**"), the members of the Committee shall elect a chair from amongst their number. If the chair of the Committee is absent from any meeting, the Committee shall select one of the other members of the Committee to preside at that meeting.

4. The Secretary of the Corporation shall be the secretary of the Committee, unless otherwise determined by the Committee. Minutes of meetings of the Committee shall be recorded and maintained by the Secretary of the Committee. Copies of the minutes shall be provided to the Board.

5. The quorum for meetings shall be a majority of the members (the "**Members**") of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

6. The Committee shall have access to such officers and employees of the Corporation and of the other consolidated subsidiaries of the Corporation (if any), and to the Corporation's external auditors and to such information respecting the Corporation, as the Committee considers to be necessary or advisable in order to perform its duties and responsibilities.

7. Meetings of the Committee shall be conducted as follows:

   (a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the Chairman, and the Corporation's external auditors or any member of the Committee may request a meeting of the Committee;

   (b) the Corporation's external auditors shall receive notice of and have the right and shall be encouraged to attend all meetings of the Committee; and

   (c) the Chief Executive Officer and the Chief Financial Officer of the Corporation shall be invited to attend all meetings of the Committee, except executive sessions and private sessions with the external auditors, and other management representatives of the Corporation shall be invited to attend as necessary.

8. The internal auditors of the Corporation (if any) and the external auditors of the Corporation shall have a direct line of communication to the Committee through the Chairman. The Corporation shall require the external auditors of the Corporation to report directly to the Committee.

C. DUTIES AND RESPONSIBILITIES

1. The overall duties and responsibilities of the Committee shall be as follows:

   (a) assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and approve the Corporation's annual and quarterly financial statements;

   (b) assess the qualifications of the external auditors;

   (c) establish and maintain a direct line of communication with the Corporation's internal (if any) and external auditors and assess their performance;

   (d) identify principal business risks;

   (e) ensure that the management of the Corporation has designed, implemented and is maintaining an effective system of disclosure controls and internal controls for the Corporation by requiring that management report at least quarterly on the measures in place, the testing done to ensure effectiveness, any areas where improvement is needed and whether there are any issues relating to the signing of the certifications required under Multilateral Instrument 52-109;

   (f) report regularly to the Board on the fulfilment of the duties and responsibilities of the Committee;

   (g) confirm that the Corporation's Disclosure Policy is adequate to ensure the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements is appropriate and periodically test the adequacy of the procedures mandated by such policy;

   (h) assess the effectiveness of the Disclosure Committee established under the Disclosure Policy;

   (i) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management and recommend changes to the Board;

   (j) review compliance with the Code of Business Conduct and Ethics and periodically review this policy and recommend to the Board changes which the Committee may deem appropriate; and

(k) review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation.

2. The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

(a) recommend to the Board a firm of external auditors to be engaged by the Corporation;

(b) review and approve the fee, scope and timing of the audit and other related services rendered by the external auditors;

(c) oversee the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management of the Corporation and the external auditor regarding financial reporting;

(d) review the audit plan of the external auditors prior to the commencement of the audit;

(e) review with the external auditors, upon completion of their audit, the:

(i) contents of their report;

(ii) scope and quality of the audit work performed;

(iii) adequacy of the Corporation's financial and auditing personnel;

(iv) co-operation received from the Corporation's personnel during the audit;

(v) internal resources used;

(vi) significant transactions outside of the normal business of the Corporation;

(vii) the major points contained in the auditor's management letter resulting from control evaluation and testing (if any); and

(viii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems (if any);

(f) pre-approve all non-audit services to be provided to the Corporation by the external auditor in accordance with applicable laws;

(g) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal audit staff or by the external auditors have been implemented; and

(h) meet in camera (i.e. without the presence of management of the Corporation) with the external auditors at least once a year prior the approval of the audited annual financial statements of the Corporation and at such other times as determined necessary or appropriate by the Committee.

3. The duties and responsibilities of the Committee as they relate to the Corporation's internal auditors (if any) shall be as follows:

(a) periodically review the internal audit function with respect to the organization, staffing and effectiveness of the internal audit department;

(b) review and approve the internal audit plan; and

(c) review significant internal audit findings and recommendations, and management's responses thereto.

4. The Committee is also charged with the responsibility to:

(a) review and approve the Corporation's financial statements (annual and interim) and management's discussion and analysis (annual and interim) as well as the financial sections of prospectuses and other public reports requiring approval by the Board before such documents are publicly disclosed by the Corporation;

(b) review regulatory filings and decisions as they relate to the Corporation's financial statements;

(c) review the minutes of any audit committee meeting of associated companies, partnerships or trusts (if any);

(d) review the Corporation's accounting policies and discuss the impact of proposed changes in accounting standards;

(e) review with management, the external auditors and if necessary with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the financial statements;

(f) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters;

(g) establish procedures for the confidential, anonymous submission by employees of the Corporation or any other consolidated subsidiary (if any) of the Corporation of concerns regarding questionable accounting or auditing matters;

(h) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation;

(i) develop a calendar of activities to be undertaken by the Committee for each ensuing year and to submit the calendar in the appropriate format to the Board following each annual general meeting of shareholders; and

(j) on an annual basis, review and assess the adequacy of the Charter and the performance of the Committee in connection therewith.

5. The Committee has the authority to:

(a) engage independent counsel and other advisors as it determines necessary to carry out its duties; and

(b) set and pay the compensation for any advisors employed by the Committee.

SCHEDULE "B"

FORM 51-101F2
REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Manitok Energy Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation'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%, included in the reserves data of the Corporation evaluated by us as of December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country)**	**Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)**			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule Associates Limited	Evaluation of the P&NG Reserves of Manitok Energy Inc., as at December 31, 2013, prepared December 2013 to April 2014	Canada	**Nil**	**304,432**	**Nil**	**304,432**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed, but did not audit or evaluate.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. 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:

Sproule Associates Limited
Calgary, Alberta, Canada
April 11, 2014

(signed) *"Paul B. Jung"*

Paul B. Jung, P. Eng.
Supervisor, Engineering and Partner

(signed) *"Khani Ghaffari"*

Khani Ghaffari, P. Eng.
Senior Petroleum Engineer and Associate

(signed) *"George Strother-Stewart"*

George Strother-Stewart, P. Geol.
Senior Petroleum Geologist and Partner

(signed) *"Harry J. Helwerda"*

Harry J. Helwerda, P. Eng., FEC, FGC (Hon.)
President & Chief Operating Officer and Director

SCHEDULE "C"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which meanings are ascribed in NI 51-101 have the same meanings herein.

Management of Manitok Energy Inc. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and 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, 2013, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator or auditor is presented in the Statement of Reserves Data and Other Oil and Gas Information of the Corporation effective as at December 31, 2013.

The Reserves and Occupational Health and Safety Committee of the Board of Directors of the Corporation has:

1. reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator or auditor;

2. met with the independent qualified reserves evaluator or auditor to determine whether any restrictions affected the ability of the independent qualified reserves evaluator or auditor to report without reservation; and

3. reviewed the reserves data with management and the independent qualified reserves evaluator or auditor.

The Reserves and Occupational Health and Safety Committee has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

4. the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

5. the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

6. the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "*Massimo M. Geremia*"	(signed) "*Robert G. Dion*"
Massimo M. Geremia President and Chief Executive Officer	Robert G. Dion Vice President, Finance and Chief Financial Officer
(signed) "*Cameron G. Vouri*"	(signed) "*Bruno P. Geremia*"
Cameron G. Vouri Chairman of Reserve and Occupational Health & Safety Committee, Director & Chief Operating Officer	Bruno P. Geremia Director

April 23, 2014