ANNUAL INFORMATION FORM

For the year ended December 31, 2014

February 20, 2015

TABLE OF CONTENTS

Glossary of Terms

Unless the context otherwise requires, in this Annual Information Form, the following terms and abbreviations have the meanings set forth below. **Additional terms relating to oil and natural gas reserves, resources and operations have the meanings set forth under "*Presentation of Oil and Gas Reserves, Resources and Production Information*".**

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

"**AECO**" means the physical storage and trading hub for natural gas on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta index prices;

"**Bank Credit Facility**" means, as of December 31, 2014, the Corporation's $1.0 billion senior unsecured, covenant-based revolving credit facility with a syndicate of financial institutions. See "*Material Contracts and Documents Affecting the Rights of Securityholders*";

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

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

"**Conversion**" means the conversion of Enerplus' business from an income trust structure (with the parent entity being the Fund) to a corporate structure (with the parent entity being the Corporation) effective January 1, 2011 by way of a plan of arrangement under the ABCA, pursuant to which, among other things, the former trust units of the Fund, each of which represented an equal undivided beneficial interest in the Fund ("**Trust Units**"), were exchanged on a one-for-one basis for Common Shares;

"**Corporation**" means Enerplus Corporation, a corporation amalgamated under the ABCA, and, where the context applies, its subsidiaries, taken as a whole;

"**Credit Facilities**" means, collectively, the Bank Credit Facility and the Senior Unsecured Notes. See "*Material Contracts and Documents Affecting the Rights of Securityholders*";

"**CSA Notice 51-324**" means Canadian Securities Administrators Staff Notice 51-324 (Revised) – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*, issued by the Canadian securities regulatory authorities;

"**Enerplus**" means (i) on and after January 1, 2011, the Corporation and, where the context applies, its subsidiaries, taken as a whole, and (ii) prior to January 1, 2011, the Fund and its subsidiaries, taken as a whole;

"**Enerplus USA**" means Enerplus Resources (USA) Corporation, a corporation organized under the laws of Delaware and a wholly-owned subsidiary of the Corporation;

"**Fund**" means Enerplus Resources Fund, formerly a trust formed pursuant to the laws of Alberta that was dissolved on January 1, 2011 in connection with the Conversion, and which was the predecessor issuer to the Corporation;

"**IFRS**" means International Financial Reporting Standards, as issued by the International Accounting Standards Board, as amended from time to time;

"**Laricina**" means Laricina Energy Ltd., a private corporation organized under the ABCA;

"**McDaniel**" means McDaniel & Associates Consultants Limited, independent petroleum consultants;

"**McDaniel Reports**" means, collectively, the independent engineering evaluations of the Corporation's oil, NGLs and natural gas reserves in Canada and the Corporation's oil, NGLs and natural gas reserves in the United States prepared by McDaniel effective December 31, 2014, utilizing commodity price forecasts of McDaniel as of January 1, 2015;

"**MD&A**" means management's discussion and analysis;

"**NSAI**" means Netherland, Sewell & Associates, Inc., independent petroleum consultants;

"**NSAI Report**" means the independent engineering evaluation of the Corporation's shale gas reserves and contingent resources in the Marcellus properties prepared by NSAI effective December 31, 2014, utilizing commodity price forecasts of McDaniel (for internal consistency in the Corporation's reserves reporting) as of January 1, 2015;

"**NI 51-101**" means National Instrument 51- 101 – *Standards of Disclosure for Oil and Gas Activities*, adopted by the Canadian securities regulatory authorities;

"**NYSE**" means the New York Stock Exchange;

"**SEC**" means the United States Securities and Exchange Commission;

"**Senior Unsecured Notes**" means, as at December 31, 2014, the US$850.8 million principal amount and $70 million principal amount of outstanding senior unsecured notes issued by Enerplus. See "*Description of Capital Structure – Senior Unsecured Notes*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*";

"**Shareholder Rights Plan**" means the amended and restated shareholder rights plan agreement between the Corporation and Computershare Trust Company of Canada, as rights agent, dated as of May 10, 2013;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c.1 (5th Supp.), as amended, including the regulations promulgated thereunder, as amended from time to time;

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

"**U.S. GAAP**" means generally accepted accounting principles in the United States.

Abbreviations and Conversions

In this Annual Information Form, the following abbreviations have the meanings set forth below:

API	American Petroleum Institute
bbls	barrels, with each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/day	barrels per day
Bcf	billion cubic feet
BcfGE(1)	one billion cubic feet of natural gas equivalent
BOE(1)	barrels of oil equivalent
BOE/day	barrels of oil equivalent per day
Mbbls	one thousand barrels
MBOE(1)	one thousand barrels of oil equivalent
Mcf	one thousand cubic feet
Mcf/day	one thousand cubic feet per day
MMBOE(1)	one million barrels of oil equivalent
MMbtu	one million British Thermal Units
MMcf	one million cubic feet
NGLs	natural gas liquids
NYMEX	the New York Mercantile Exchange
Tcf	trillion cubic feet
WTI	West Texas Intermediate crude oil that serves as the benchmark crude oil for the NYMEX crude oil contract delivered in Cushing, Oklahoma

Note:

(1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to BcfGEs. For further information, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Barrels of Oil and Cubic Feet of Gas Equivalent*".

In this Annual Information Form, unless otherwise indicated, all dollar amounts are in Canadian dollars and all references to "**$**" and "**CDN$**" are to Canadian dollars. References to "**US$**" are to U.S. dollars. On December 31, 2014, the exchange rate for one U.S. dollar, expressed in Canadian dollars and based upon the noon buying rate of the Bank of Canada, was CDN$1.1601.

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.471

Presentation of Oil and Gas Reserves, Resources and Production Information

NOTE TO READER REGARDING OIL AND GAS INFORMATION, DEFINITIONS AND NATIONAL INSTRUMENT 51-101

The oil and gas reserves and operational information of the Corporation contained in this Annual Information Form contains the information required to be included in the Statement of Reserves Data and Other Oil and Gas Information pursuant to NI 51-101 adopted by the Canadian securities regulatory authorities. Readers should also refer to the Report on Reserves Data by McDaniel and NSAI attached as Appendix A and the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix B. The effective date for the Statement of Reserves Data and Other Oil and Gas Information contained in this Annual Information Form is December 31, 2014 and the preparation dates for such information are January 28, 2015 for the McDaniel Reports and January 20, 2015 for the NSAI Report.

Certain of the following definitions and guidelines are contained in the Glossary to NI 51-101 contained in CSA Notice 51-324, which incorporates certain definitions from the COGE Handbook. Readers should consult CSA Notice 51- 324 and the COGE Handbook for additional explanation and guidance.

DISCLOSURE OF RESERVES AND PRODUCTION INFORMATION

Presentation of Information

In this Annual Information Form, all oil and natural gas production and realized product prices information is presented on a "company interest" basis (as defined below), unless expressly indicated that it is being presented on a "gross" or "net" basis. "**Company interest**" means, in relation to the Corporation's interest in production, its working interest (operating or non-operating) share before deduction of royalties, plus the Corporation's royalty interests in production. "Company interest" is not a term defined or recognized under NI 51-101 and does not have a standardized meaning under NI 51-101. Therefore, the "company interest" production of the Corporation may not be comparable to similar measures presented by other issuers, and investors are cautioned that "company interest" production should not be construed as an alternative to "gross" or "net" production calculated in accordance with NI 51-101.

In this Annual Information Form, all natural gas information, including reserves, resources and production, includes shale gas, unless expressly indicated that it is being presented on a separate basis. The Corporation's actual oil and natural gas reserves and future production may be greater than or less than the estimates provided in this Annual Information Form. The estimated future net revenue from the production of such oil and natural gas reserves does not represent the fair market value of such reserves. See "*Oil and Natural Gas Reserves – Summary of Reserves*" for additional information.

Notice to U.S. Readers

Data on oil and natural gas reserves contained in this Annual Information Form has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, although the SEC now generally permits oil and gas issuers, in their filings with the SEC, to disclose both proved reserves and probable reserves (each as defined in the SEC rules), the SEC definitions of proved reserves and probable reserves may differ from the definitions of "proved reserves" and "probable reserves" under Canadian securities laws. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above with respect to production information, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Moreover, in accordance with Canadian disclosure requirements, the Corporation has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC generally requires that reserves estimates be prepared using an unweighted average of the closing prices for the applicable commodity on the first day of each of the twelve months preceding the company's fiscal year-end, with the option of also disclosing reserves estimates based upon future or other prices. As a consequence of the foregoing, the Corporation's reserves estimates and production volumes may not be comparable to those made by companies utilizing United States reporting and disclosure standards. Additionally, the SEC prohibits disclosure of oil and gas resources in SEC filings, including contingent resources, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not be construed as, reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see "– *Disclosure of Contingent Resources*" below.

BARRELS OF OIL AND CUBIC FEET OF GAS EQUIVALENT

The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to and BcfGEs. BOEs, MBOEs, MMBOEs, and BcfGEs may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do 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.

DISCLOSURE OF CONTINGENT RESOURCES

In this Annual Information Form, the Corporation has disclosed estimated volumes of economic "contingent resources" which relate to the Corporation's interests in its Fort Berthold property located in North Dakota, its Marcellus shale gas properties located in Pennsylvania, its crude oil waterflood properties located in Alberta and Saskatchewan and its Wilrich natural gas assets located in Alberta.

"**Resources**" are quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, including the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

"**Contingent resources**" are defined as those quantities of hydrocarbons estimated, on a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are economically recoverable based on McDaniel's January 1, 2015 forecast prices. Contingent resources are also classified based on the project maturity into "development pending", "development on hold", "development unclarified" and "development not viable" sub-classes. All of the Corporation's resources fall into "development pending" and "development on hold" sub-classes. "Development pending" sub-class is assigned to contingent resources for a particular project where resolution of the final conditions for development is being actively pursued (there is a high chance of development). "Development on hold" sub-class is assigned where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

The economic contingent resources estimates in this Annual Information Form are presented as the "**best estimate**" of the quantity that will actually be recovered, meaning that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate. The recovery and resources estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

Resources and contingent resources do not constitute, and should not be confused with, reserves. See "*Business of the Corporation – Description of Properties*" and "*Risk Factors – The Corporation's actual reserves and resources will vary from its reserves and resources estimates, and those variations could be material*".

INTERESTS IN RESERVES, PRODUCTION, WELLS AND PROPERTIES

In addition to the terms having defined meanings set forth in CSA Notice 51-324, the terms set forth below have the following meanings when used in this Annual Information Form:

"**gross**" means:

(i) in relation to the Corporation's interest in production or reserves, its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

(ii) in relation to wells, the total number of wells in which the Corporation has an interest; and

(iii) in relation to properties, the total area in which the Corporation has an interest.

"**net**" means:

(i) in relation to the Corporation's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

(ii) in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(iii) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**working interest**" means the percentage of undivided interest held by the Corporation in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the Corporation the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

RESERVES CATEGORIES AND LEVELS OF CERTAINTY FOR REPORTED RESERVES

In this Annual Information Form, the following terms have the meaning assigned thereto in CSA Notice 51-324 and the COGE Handbook:

"**reserves**" are 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: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed. Reserves may be divided into proved and probable categories according to the degree of certainty associated with the estimates.

"**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.

"**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.

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

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

DEVELOPMENT AND PRODUCTION STATUS

Each of the reserves categories reported by the Corporation (proved and probable) may be divided into developed and undeveloped categories:

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

- "**developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- "**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

DESCRIPTION OF PRICE AND COST ASSUMPTIONS

"**Forecast prices and costs**" means future prices and costs that are:

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

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

Presentation of Financial Information

The Corporation has converted its financial reporting from IFRS to U.S. GAAP as (i) over 50% of the book value of the assets (as previously calculated under IFRS) were in the United States, and (ii) over 50% of the Common Shares are held by U.S. residents. Reporting under U.S. GAAP began with the financial statements for the year ended December 31, 2013.

The Corporation continues to qualify as a foreign private issuer for its U.S. securities filings as less than 50% of the book value of its assets is in the United States, as calculated under U.S. GAAP as at June 30, 2014. The Corporation is required to reassess this annually at the end of the second quarter. See "*Risk Factors – Government regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs*".

Forward-Looking Statements and Information

This Annual Information Form contains certain forward-looking statements and forward-looking information (collectively, "forward-looking information") within the meaning of applicable securities laws which are based on the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plan", "intend", "guidance", "objective", "strategy", "should", "believe" and similar expressions are intended to identify forward-looking statements and forward-looking information. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Corporation believes the expectations reflected in such forward-looking information are reasonable but no assurance can be given that these expectations will prove to be correct, and such forward-looking information included in this Annual Information Form should not be unduly relied upon. Such forward-looking information speaks only as of the date of this Annual Information Form and the Corporation does not undertake any obligation to publicly update or revise any forward-looking information, except as required by applicable laws.

In particular, this Annual Information Form contains forward-looking information pertaining to the following:

- the quantity of, and future net revenues from, the Corporation's reserves and/or contingent resources;
- crude oil, NGLs and natural gas production levels;
- commodity prices, foreign currency exchange rates and interest rates;
- operating expenditures;
- current capital expenditure programs, drilling programs, development plans and other future expenditures, including the planned allocation of capital expenditures among the Corporation's properties and the sources of funding for such expenditures;
- supply and demand for oil, NGLs and natural gas;
- the Corporation's business strategy, including its asset and operational focus;
- future acquisitions and dispositions and future growth potential;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves and/or resources through acquisitions and development;
- schedules for and timing of certain projects and the Corporation's strategy for growth;
- the Corporation's future operating and financial results;
- future abandonment and reclamation costs;
- future dividends that may be paid by the Corporation;
- the Corporation's tax pools and the time at which the Corporation may incur certain income or other taxes; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

The forward-looking information contained in this Annual Information Form reflects several material factors and expectations and assumptions made by the Corporation including, without limitation, that: the Corporation's current commodity price and other cost assumptions will generally be accurate; the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; the Corporation's conduct and results of operations will be consistent with its expectations; the Corporation and its industry partners will have the ability to develop the Corporation's oil and gas properties in the manner currently contemplated; a lack of infrastructure does not result in the Corporation curtailing its production and/or receiving reductions to its realized prices; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; the estimates of the Corporation's reserves and resources volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; and there will be sufficient availability of services and labour to conduct the Corporation's operations as planned.

The Corporation's current 2015 capital expenditure budget contained in this Annual Information Form assumes: WTI price of US$55/bbl; NYMEX gas price of US$2.75/Mcf; AECO gas price of $2.50/GJ; a foreign exchange rate of USD/CDN 1.25; and estimated curtailment ranging from 6,000 BOE/day to 7,000 BOE/day in annual average natural gas production from the Marcellus.

The Corporation believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable at this time but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The Corporation's actual results could differ materially from those anticipated in this forward-looking information as a result of both known and unknown risks, including the risk factors set forth under "*Risk Factors*" in this Annual Information Form and risks relating to:

- volatility, including further decline, in market prices for oil, NGLs and natural gas, including changes in supply or demand for those products;
- actions by governmental or regulatory authorities including different interpretations of applicable laws, treaties or administrative positions as well as changes in income tax laws or changes in royalty regimes and incentive programs relating to the oil and gas industry;
- unanticipated operating results, including changes or fluctuations in oil, NGLs and natural gas production levels;
- changes in foreign currency exchange rates and interest rates;
- changes in development plans by the Corporation or third party operators;
- the ability of the Corporation to access required capital;
- changes in capital and other expenditure requirements and debt service requirements;
- liabilities and unexpected events inherent in oil and gas operations, including geological, technical, drilling and processing risks, as well as unforeseen title defects or litigation;
- actions of and reliance on industry partners;
- uncertainties associated with estimating reserves and resources;
- competition for, among other things, capital, acquisitions of reserves and resources, undeveloped lands, access to third party processing capacity, and skilled personnel;
- incorrect assessments of the value of acquisitions or the failure to complete dispositions;
- constraints on, or the unavailability of adequate infrastructure, including pipeline and transportation capacity, to deliver the Corporation's production to market;
- the Corporation's success at the acquisition, exploitation and development of reserves and resources;
- changes in general economic, market (including credit market) and business conditions in Canada, North America and worldwide; and
- changes in tax, environmental, regulatory or other legislation applicable to the Corporation and its operations, and the Corporation's ability to comply with current and future environmental legislation and regulations and other laws and regulations.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail throughout this Annual Information Form and in the Corporation's MD&A for the year ended December 31, 2014, which is available through the internet on the Corporation's SEDAR profile at www.sedar.com, on the Corporation's EDGAR profile at www.sec.gov as part of the annual report on Form 40-F filed with the SEC together with this Annual Information Form, and on the Corporation's website at www.enerplus.com. Readers are also referred to the risk factors described in this Annual Information Form under "*Risk Factors*" and in other documents the Corporation files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the Corporation or electronically on the internet on the Corporation's SEDAR profile at www.sedar.com, on the Corporation's EDGAR profile at www.sec.gov and on the Corporation's website at www.enerplus.com.

Corporate Structure

ENERPLUS CORPORATION

The Corporation was incorporated on August 12, 2010 under the ABCA for the purposes of participating in the Conversion under which the business of the Fund, as the Corporation's predecessor, was transitioned to the Corporation. As part of the plan of arrangement under the ABCA pursuant to which the Conversion was effected, the Corporation was amalgamated with several other former direct and indirect subsidiaries of the Fund on January 1, 2011 and continued as the Corporation. Prior to the Conversion, the business of the Corporation was carried on by the Fund and its subsidiaries as an income trust since 1986.

Effective May 11, 2012, the Corporation amended and restated its articles of amalgamation in connection with the implementation of a stock dividend program. The Corporation amended the rights, privileges, restrictions and conditions in respect of Common Shares to set forth the terms and conditions pursuant to which the Corporation may issue Common Shares as payment of all or any portion of dividends declared on the Common Shares for those shareholders who elect to receive stock dividends instead of cash dividends. The Corporation's board of directors suspended the stock dividend program effective September 19, 2014. See "*Description of Capital Structure – Common Shares*" and "*Dividends – Stock Dividend Program*".

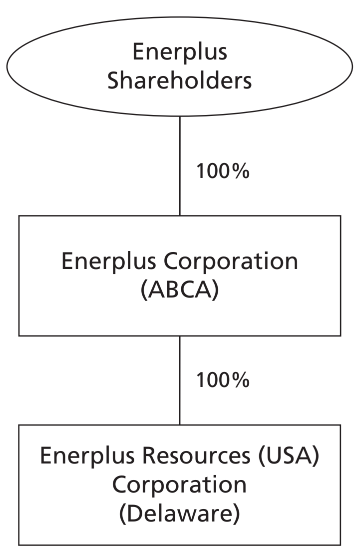
The head, principal and registered office of the Corporation is located at The Dome Tower, 3000, 333 – 7th Avenue S.W., Calgary, Alberta, T2P 2Z1. The Corporation also has a U.S. office located at 950 - 17th Street, Suite 2200, Denver, Colorado, 80202-2805. The Common Shares are currently traded on the TSX and the NYSE under the symbol "ERF".

MATERIAL SUBSIDIARIES

As of December 31, 2014, Enerplus USA was the only material subsidiary of Enerplus Corporation. All of the issued and outstanding securities of Enerplus USA are owned by the Corporation.

ORGANIZATIONAL STRUCTURE

The simplified organizational structure of Enerplus Corporation and its material subsidiary as of December 31, 2014 is set forth below.



General Development of the Business

DEVELOPMENTS IN THE PAST THREE YEARS

Developments in 2012

FINANCINGS AND MONETIZATION ACTIVITIES

On February 8, 2012, the Corporation completed a bought-deal public offering of 14,708,500 Common Shares for aggregate net proceeds of approximately $331 million. The Corporation initially used the net proceeds of this offering to reduce its outstanding indebtedness under the Bank Credit Facility and subsequently utilized such proceeds to fund a portion of its capital expenditure program in 2012.

On May 15, 2012, the Corporation completed a private placement offering of senior unsecured notes in an aggregate principal amount of approximately US$405 million, issued in three tranches, with terms ranging from seven to 12 years and with interest rates of approximately 4.40%. The Corporation used the net proceeds of this offering to reduce its outstanding indebtedness under the Bank Credit Facility. See "*Description of Capital Structure – Senior Unsecured Notes*".

In August 2012, the Corporation sold all of its common shares in Laricina for net after tax proceeds of approximately $141 million. The net proceeds were used to reduce the Corporation's outstanding indebtedness and subsequently used to fund a portion of its 2012 capital expenditure program.

ACQUISITION OF BAKKEN OIL ASSETS IN MONTANA

On December 17, 2012, the Corporation completed an acquisition of an additional 20% working interest in the Sleeping Giant area in the Elm Coulee field in Richland County in Montana for approximately $118 million, including estimated closing adjustments. This acquisition included approximately 1,550 BOE/day of production and was complementary to the Corporation's existing operations in the Sleeping Giant area. This acquisition consolidated the Corporation's working interest in the subject leases to approximately 90%. For a description of the Corporation's Bakken interests, see "*Business of the Corporation – Description of Properties – U.S. Crude Oil Properties*".

SALE OF NON-CORE MANITOBA ASSETS

On December 19, 2012, the Corporation completed a sale of its crude oil assets located in the Virden/Daly region of Manitoba for approximately $218 million, including estimated closing adjustments. This disposition included approximately 1,600 BOE/day of crude oil production. A portion of the proceeds from the sale were used to fund the acquisition of the Corporation's additional working interest in Bakken oil assets in Montana described above, with the balance utilized to reduce indebtedness under the Bank Credit Facility.

Developments in 2013

ACQUISITION OF ADDITIONAL ASSETS

Property and land acquisitions in 2013 totaled $244.8 million, the most significant consisting of additional interest in the Corporation's core Marcellus properties for $157.9 million in the United States and $34.0 million for additional interest in the Pouce Coupe waterflood property in Canada. See "*Business of the Corporation – Description of Properties*".

SALE OF NON-CORE ASSETS

In 2013, the Corporation realized proceeds of approximately $365.1 million from disposition activities involving the Corporation's non-core assets located in Canada and the United States. These dispositions included in aggregate approximately 2,700 BOE/day of production. The proceeds from the Corporation's disposition activities were used to fund the Corporation's capital program and to reduce indebtedness under the Bank Credit Facility.

SUCCESSION OF PRESIDENT & CHIEF EXECUTIVE OFFICER

Mr. Gordon J. Kerr, the former President & Chief Executive Officer of the Corporation, stepped down as an officer and director of the Corporation effective June 30, 2013. Mr. Ian C. Dundas succeeded Mr. Kerr as the President & Chief Executive Officer and director of the Corporation effective July 1, 2013. Prior thereto, Mr. Dundas held the position of the Executive Vice President & Chief Operating Officer of the Corporation. See "*Directors and Officers*".

Developments in 2014

FINANCING

On September 3, 2014, the Corporation completed a private placement offering of 3.79% senior unsecured notes in an aggregate principal amount of US$200 million due September 3, 2026. The Corporation used the net proceeds of this offering to reduce its outstanding indebtedness under the Bank Credit Facility. See "*Description of Capital Structure – Senior Unsecured Notes*".

SALE OF NON-CORE ASSETS

In 2014, the Corporation realized proceeds of over $200 million from disposition activities involving the Corporation's non-core assets. These dispositions included in aggregate approximately 3,500 BOE/day of production. The proceeds from the Corporation's disposition activities were used to fund the Corporation's capital program and to reduce indebtedness under the Bank Credit Facility.

SUCCESSION OF CHAIRMAN OF THE BOARD OF DIRECTORS

Mr. Doug Martin, the former Chairman of the board of directors of the Corporation, retired from this position effective June 1, 2014 and as a director of the Corporation effective November 30, 2014. Mr. Elliott Pew succeeded Mr. Martin as the Chairman of the board of directors of the Corporation effective June 1, 2014. Mr. Pew has been a director of the Corporation since September 2010. See "*Directors and Officers*".

Business of the Corporation

OVERVIEW

The Corporation executed on its 2014 capital programs to deliver both production growth and funds flow growth, while maintaining capital discipline and a strong balance sheet. Capital spending in 2014 was focused on its four core areas, with a 64% weighting to oil projects. Within the United States, the Corporation's capital program focused on the development of its crude oil and natural gas core areas of operation, which includes its North Dakota and Montana crude oil assets in the Williston Basin, and its natural gas interests in northeast Pennsylvania. Capital spending in the United States was just over 60% of total capital spending in 2014. Capital spending in Canada was directed to its Canadian crude oil waterflood assets, as well as the on-going delineation of its natural gas assets in the Canadian Deep Basin in northwest Alberta. In addition to capital spending on development and delineation within its core areas, the Corporation continued to concentrate its portfolio through divestment activities. During 2014, the Corporation sold certain non-core assets with 3,500 BOE/day of non-operated production, primarily natural gas production in Canada.

The Corporation's oil and natural gas property interests are located in western Canada in the provinces of Alberta, British Columbia and Saskatchewan, and in the United States, primarily in the states of Montana, North Dakota, Pennsylvania and West Virginia. The Corporation's major producing properties generally have related field production facilities and infrastructure to accommodate its production.

Production volumes for the year ended December 31, 2014 from the Corporation's properties consisted of approximately 42% crude oil and NGLs and 58% natural gas, on a BOE basis. The Corporation's 2014 average daily production was 103,130 BOE/day, comprised of 40,208 bbls/day of crude oil, 3,565 bbls/day of NGLs and 356,142 Mcf/day of natural gas, an increase of approximately 15% compared to 2013 average daily production of 89,793 BOE/day, comprised of 38,250 bbls/day of crude oil, 3,472 bbls/day of NGLs and 288,423 Mcf/day of natural gas. The increase in average daily production during 2014 is largely attributable to growth in crude oil production volumes from the Corporation's Fort Berthold, North Dakota properties, as well as increased natural gas production volumes from the Marcellus. Approximately 43% of the Corporation's 2014 production was from Canada, with the remaining 57% from the United States. 57% of the Corporation's 2014 production was operated by the Corporation; 43% was operated by industry partners.

As at December 31, 2014, the oil and natural gas property interests held by the Corporation were estimated to contain proved plus probable gross reserves of 157,293 Mbbls of light and medium crude oil, 43,138 Mbbls of heavy crude oil, 12,798 Mbbls of NGLs, 456,430 MMcf of natural gas and 839,940 MMcf of shale gas, for a total of 429,291 MBOE. The Corporation's proved reserves represented approximately 66% of total proved plus probable reserves, and approximately 50% of the Corporation's proved plus probable reserves were weighted to crude oil and NGLs. See "*Oil and Natural Gas Reserves*".

Unless otherwise noted, (i) all production and operational information in this Annual Information Form is presented as at or, where applicable, for the year ended, December 31, 2014, (ii) all production information represents the Corporation's company interest in production from these properties, which includes overriding royalty interests of the Corporation but is calculated before deduction of royalty interests owned by others, and (iii) all references to reserves volumes represent gross reserves using forecast prices and costs. See "*Presentation of Oil and Gas Reserves, Resources and Production Information*".

SUMMARY OF PRINCIPAL PRODUCTION LOCATIONS

During the year ended December 31, 2014, on a BOE basis, 43% of the Corporation's production was derived from Canada (32% from Alberta, 8% from Saskatchewan and 3% from British Columbia) and approximately 57% from the United States (21% from North Dakota, 30% from Pennsylvania, 6% from Montana, and minimal amounts from West Virginia). The following table describes the average daily production from the Corporation's principal producing properties and regions during the year ended December 31, 2014.

2014 Average Daily Production from Principal Properties and Regions

	Products					
	Crude Oil					
Property/Region	**Light and Medium**	**Heavy**	**NGLs**	**Natural Gas**	**Shale Gas**	**Total**
	(bbls/day)	(bbls/day)	(bbls/day)	(Mcf/day)	(Mcf/day)	(BOE/day)
United States						
Marcellus, Pennsylvania					188,168	31,361
Fort Berthold, North Dakota	19,139	–	1,077	8,834	–	21,688
Sleeping Giant, Montana	4,402	–	11	8,210	–	5,782
Total United States	23,541	–	1,088	17,044	188,168	58,831
Canada						
Medicine Hat Glauconitic "C" Unit, Alberta	–	4,001	–	279	–	4,048
Shackleton, Saskatchewan	–	–	–	18,230	–	3,038
Hanlan-Robb, Alberta	–	–	57	16,466	–	2,801
Tommy Lakes, British Columbia	62	–	267	12,835	–	2,468
Brooks, Alberta	–	1,749	24	3,504	–	2,357
Bantry, Alberta	1	–	–	10,943	–	1,825
Freda Lake, Saskatchewan	1,793	–	–	–	–	1,793
Neptune, Saskatchewan	1,779	–	–	–	–	1,779
Giltedge, Alberta	–	1,663	–	358	–	1,723
Pembina 5 Way, Alberta	1,353	–	80	1,187	–	1,631
Pouce Coupe, Alberta	554	–	86	3,374	–	1,203
Pine Creek, Alberta	7	–	237	5,336	–	1,133
Verger, Alberta	–	–	1	6,551	–	1,093
Hanna Garden, Alberta	–	–	–	5,794	–	966
Joarcam, Alberta	594	–	25	1,537	–	875
Elmworth, Alberta(1)	1	–	273	3,431	–	846
Progress, Alberta	398	–	47	2,363	–	839
Other Canada	1,529	1,183	1,380	58,742	–	13,881
Total Canada	8,071	8,596	2,477	150,930	–	44,299
Total	31,612	8,596	3,565	167,974	188,168	103,130

Note:

(1) Sold effective September 30, 2014.

For additional information on the Corporation's oil and natural gas properties, see "*Description of Properties*".

CAPITAL EXPENDITURES AND COSTS INCURRED

In 2014, the Corporation invested approximately $811 million through its capital program, which was approximately 19% higher than the $681 million invested in 2013. The Corporation continued to focus the majority of its spending on its core assets, spending approximately $344 million on the Fort Berthold crude oil property, $159 million on Marcellus assets, $177 million on Canadian crude oil properties and $125 million on liquids-rich deep gas properties in Canada.

In the financial year ended December 31, 2014, the Corporation made the following expenditures in the categories noted, as prescribed by NI 51-101:

	Property Acquisition Costs		Exploration Costs	Development Costs
	Proved	Unproved		
	($ in millions)			
Canada	$ –	$ 2.0	$ 44.6	$ 263.7
United States	6.8	9.7	1.7	501.0
Total	$ 6.8	$ 11.7	$ 46.3	$ 764.7

Based on the commodity price environment as of the date hereof, the Corporation currently expects its 2015 exploration and development capital spending to be approximately $480 million, with over 85% projected to be invested in the Corporation's Canadian and U.S. crude oil projects. The Corporation currently expects to invest approximately 55% of its planned 2015 capital spending on its Fort Berthold property in the United States. In addition, the Corporation intends to spend approximately 10% of its 2015 capital spending on drilling projects in its Marcellus natural gas properties in the northeast region of Pennsylvania. In Canada, the Corporation intends to focus its 2015 capital spending on its Brooks waterflood asset, along with a modest program in the Wilrich.

The Corporation intends to finance its 2015 capital expenditure program through a combination of internally generated cash flow and debt. The Corporation will review its 2015 capital investment plans regularly throughout the year in the context of prevailing economic conditions, commodity prices and potential acquisitions, and make adjustments as it deems necessary. See "*Forward Looking Statements and Information*".

For further information regarding the Corporation's properties and its 2014 exploration and development activities see "*– Description of Properties*" below.

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes the number and type of wells that the Corporation drilled or participated in the drilling of for the year ended December 31, 2014, in each of Canada and the United States. Wells have been classified in accordance with the definitions of such terms in NI 51-101.

	Canada				United States			
	Development Wells		Exploratory Wells		Development Wells		Exploratory Wells	
Category of Well	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil wells	72	35	1	–	110	27	–	–
Natural gas wells	17	7	1	1	131	19	–	–
Service wells	18	5	–	–	–	–	–	–
Dry and abandoned wells	1	–	–	–	–	–	–	–
Total	108	47	2	1	241	46	0	0

For a description of the Corporation's planned 2015 development plans and the anticipated sources of funding these plans, see "*– Capital Expenditures and Costs Incurred*" above.

OIL AND NATURAL GAS WELLS AND UNPROVED PROPERTIES

The following table summarizes, as at December 31, 2014, the Corporation's interests in producing wells and in non-producing wells which were not producing but which may be capable of production, along with the Corporation's interests in unproved properties (as defined in

NI 51-101). Although many wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the proportion of oil or natural gas production that constitutes the majority of production from that well.

	Producing Wells				Non-Producing Wells				Unproved Properties (acres)	
	Oil		Natural Gas		Oil		Natural Gas			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Alberta	1,562	852	5,556	3,307	635	281	703	254	619,823	346,652
Saskatchewan	824	151	2,264	2,143	302	39	233	207	201,185	180,542
British Columbia	–	–	161	147	–	–	19	12	63,277	39,760
Ontario	–	–	–	–	–	–	–	–	32,882	–
United States										
Montana	256	181	1	1	2	1	–	–	2,760	586
North Dakota	346	118	–	–	34	13	–	–	6,105	6,105
Pennsylvania	–	–	649	69	–	–	133	19	142,915	47,468
West Virginia	–	–	1	1	–	–	1	1	23,386	23,386
Maryland	–	–	–	–	–	–	–	–	157	157
Utah	–	–	–	–	–	–	–	–	24	20
Total	**2,988**	**1,302**	**8,632**	**5,668**	**973**	**334**	**1,089**	**493**	**1,092,514**	**644,676**

The Corporation expects its rights to explore, develop and exploit on approximately 68,000 net acres of unproved properties in Canada and the United States to expire prior to December 31, 2015 in the ordinary course. The Corporation has no material work commitments on such properties and, where the Corporation determines appropriate, it can extend expiring leases by either making the necessary applications to extend or performing the necessary work.

DESCRIPTION OF PROPERTIES

Outlined below is a description of the Corporation's Canadian and U.S. crude oil and natural gas properties and assets.

Canadian Crude Oil Properties

OVERVIEW

The Corporation's Canadian crude oil production represents approximately 40% of its total crude oil production. This production comes primarily from low decline properties under waterflood, which provide the Corporation with a stable production base and generate free cash flow to support investment in the Corporation's growth plays, as well as its dividend. In a waterflood, water is injected into the formation to supplement the original reservoir pressure and provide a drive mechanism to move additional oil to producing wells. Pressure maintenance and the production of oil from water injection can result in a production profile with more predictable and stable declines and higher recovery of reserves. Infill drilling and well/injector optimization are effective methods of improving reserves recovery even further. These properties have associated crude oil production installations for emulsion treatment and injection or water disposal. The Canadian crude oil portfolio includes a variety of properties producing from the Cardium, Viking, Boundary Lake, Ratcliffe, Sparky/Lloydminster, Lower Mannville and Glauconitic formations. On a production basis, the Corporation operated over 90% of its Canadian crude oil producing properties during 2014.

In 2014, the Corporation's five largest crude oil producing properties were Medicine Hat, Brooks, Freda Lake, Neptune and Giltedge, all of which are located in Alberta with the exception of Freda Lake, which is located in Saskatchewan. The Corporation's Canadian crude oil production averaged 16,667 bbls/day in 2014, representing approximately 16% of the Corporation's total production for the year. A total of 97.8 MMBOE of proved plus probable reserves were associated with these assets at December 31, 2014, representing 23% of the Corporation's total proved plus probable reserves.

In 2014, the Corporation invested approximately $177 million in its Canadian crude oil assets with approximately 47% directed to drilling and completions and the remainder on plant and facility enhancements to support future activities. The Corporation drilled 30.2 net crude oil wells in Canada in 2014, advancing projects targeting the Ratcliffe, Lower Mannville, Midale, Glauconitic, Cardium and Boundary Lake plays. At

Brooks, 14 wells were drilled as part of a 55 well drilling program. At Medicine Hat, the Corporation drilled seven injection wells and seven production wells. Technical work for the Corporation's second polymer project at Medicine Hat is ongoing.

CONTINGENT RESOURCES ESTIMATE

The Corporation has conducted an internal evaluation of the contingent resources associated with a portion of its crude oil waterflood properties which has resulted in a "best estimate" of 59.3 MMBOE being classified as economic contingent resources effective as of December 31, 2014. These contingent resources are economic based on the forecast price and cost assumptions used in the Corporation's 2014 year-end reserves evaluations. Improved oil recovery from eleven existing waterfloods through optimization work accounts for approximately 25.0 MMBOE of the total. Approximately 34.3 MMBOE of the total is attributable to enhanced oil recovery ("**EOR**") projects in the Corporation's Giltedge property and the Medicine Hat Glauconitic "C" Unit where projects are underway. As work proceeds and assessed results continue to support the economic viability of these projects, the Corporation expects that contingent resources will be reclassified as reserves. Although further EOR projects are being contemplated on certain of the Corporation's other Canadian crude oil properties, these have not been fully evaluated and no contingent resources have been assessed. There is no certainty that it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources". Significant positive factors embedded in this estimate include well-established waterflood technology and a long history of waterflood performance data. The EOR estimates are based on incremental recovery from higher displacement efficiency without any improvement in areal sweep. A significant negative factor relevant to this estimate is the geological complexity and its effect on injector producer connectivity. Of the 59.3 MMBOE being classified as economic contingent resources, 58.2 MMBOE of these resources are classified into "development pending" project maturity subclass as the Corporation is actively pursuing these projects. The remaining 1.1 MMBOE are classified into "development on hold" subclass as development of these projects is currently not being pursued. The contingency preventing these resources from being classified as reserves is the early stage of implementation to the specific waterfloods. There are a number of inherent risks and contingencies associated with the development of these properties including the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, acquisitions, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in this Annual Information Form.

For additional information on the disclosure of contingent resources, including with respect to the presentation of the "best estimate" of contingent resources, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Disclosure of Contingent Resources*".

Canadian Natural Gas Properties

OVERVIEW

The Corporation's Canadian natural gas properties are located in Alberta, Saskatchewan and British Columbia. Its primary focus area is within the Deep Basin region where the Corporation holds approximately 162,000 net acres of high working interest lands. These lands include approximately 77,000 net acres targeting the Stacked Mannville zones 60,000 of which are in the Wilrich formation) and 85,000 net acres in the Willesden Green region of Alberta, targeting the liquids-rich Duvernay formation. The Corporation has additional natural gas properties producing from the Nikannassin and Bluesky formations, as well as shallow gas producing assets at Shackleton, in southwest Saskatchewan, and Verger, Hanna Garden and Medicine Hat South in Alberta. In 2014, the Corporation directed its capital spending program on the Wilrich and Duvernay formations that it believes provide stronger economic returns than those provided by shallow gas assets or other conventional natural gas assets within its portfolio.

The Corporation invested approximately $125 million in its Canadian natural gas assets in the Deep Basin in 2014 in both operated and non-operated assets. The Corporation continued to delineate its Wilrich position in the Ansell area of Alberta, drilling 3.2 wells and bringing one well on-stream during 2014. The Corporation also drilled two horizontal Duvernay wells during 2014 in the Willesden Green area of central Alberta. The wells were brought on-stream in late June and early October, respectively, and have met the Corporation's expectations on liquids content based upon its geotechnical analysis.

The Corporation's Canadian natural gas production averaged 150,930 Mcf/day in 2014. Canadian natural gas properties proved plus probable reserves totaled 280.8 BcfGE at December 31, 2014, representing approximately 11% of the Corporation's proved plus probable reserves measured on a BOE basis. The Corporation's largest producing Canadian natural gas properties in 2014 were its Shackleton property in Saskatchewan, Hanlan-Robb, Bantry and Verger in Alberta, and its Tommy Lakes property in northern British Columbia.

CONTINGENT RESOURCES ESTIMATE

The Corporation has conducted an internal evaluation of the contingent resources associated with a portion of Canadian natural gas assets targeting the Wilrich formation. This assessment has resulted in a "best estimate" of 242.6 BcfGE of economic contingent resources effective as of December 31, 2014. This internal estimate has been audited by McDaniel. The development of these resources is contingent on confirmation of commercial productivity of the undrilled reserves locations and subsequent internal development project approval. As the development of these contingent resources is expected to immediately follow development of the reserves, all of these contingent resources are classified into the "development pending" project maturity subclass. The classification of the resources in the Wilrich formation as contingent resources is based on the productivity of the Wilrich formation being similar to the Corporation's adjacent Wilrich producing reserves and offset productivity of competitor wells. These contingent resources have been geologically mapped with significant control from wells drilled for deeper horizons and are economic based on the price and cost assumptions used in the Corporation's 2014 year-end reserves evaluations. Significant factors embedded in this estimate include an average recovery of five BcfGE per well with ultimate recovery of 66% of the estimated original natural gas in place. There is no certainty that it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources". There are a number of inherent risks and contingencies associated with the development of these properties including the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, acquisitions, funding and provision of services and those other risks and contingencies described above and under "*Risk Factors*" in this Annual Information Form.

U.S. Crude Oil Properties

OVERVIEW

The Corporation's primary U.S. crude oil properties are located in the Fort Berthold region of North Dakota and in Richland County, Montana. The Corporation has an approximate 83% average working interest in Fort Berthold with 74,000 net acres of land located primarily in Dunn and McKenzie counties. Production from the Fort Berthold region is from the Bakken and Three Forks formations and consists of light sweet crude oil (42° API) and some associated natural gas and natural gas liquids. Fort Berthold production averaged 21,688 BOE/day in 2014. The Corporation added approximately 23.9 MMBOE of proved plus probable reserves, including technical revisions, at Fort Berthold during 2014 for a total of 122.6 MMBOE of proved plus probable reserves associated with this property. The Corporation owns a 90% working interest in the Sleeping Giant property located in the Elm Coulee field in Richland County, Montana. Sleeping Giant is a mature, light oil property which produced 5,768 BOE/day on average in 2014 from the Bakken formation. The Corporation believes there is additional upside potential at the Sleeping Giant property through production optimization, refracs, limited infill drilling and the potential for enhanced oil recovery.

Overall, the Corporation's U.S. crude oil and natural gas liquids production averaged 24,629 bbls/day in 2014, representing 56% of the Corporation's 2014 average daily crude oil and liquids production on a BOE basis. The Corporation had 144.7 MMBOE of proved plus probable reserves associated with these assets at December 31, 2014, representing 34% of its total proved plus probable reserves.

The Corporation spent approximately $344 million of capital on its U.S. crude oil assets in Fort Berthold in 2014, representing the single largest capital investment in the Corporation's portfolio. In 2014, there were 27.2 net horizontal wells drilled in the Fort Berthold region, targeting both the Bakken and Three Forks formations (consisting of 1.0 short lateral wells and 23.4 long lateral wells and 2.8 three-mile lateral wells) with approximately 18.4 net wells brought on-stream during 2014.

CONTINGENT RESOURCES ESTIMATE

An evaluation of the Corporation's interests in the Bakken and Three Forks formations at Fort Berthold, North Dakota conducted internally by the Corporation and audited by McDaniel has attributed a "best estimate" of 114.5 MMBOE of economic contingent resources attributable to these formations, effective as of December 31, 2014, an increase of approximately 200% from the estimate as of December 31, 2013. The increase was a result of the reassessment of original oil in place conducted by McDaniel. As described above, the Corporation converted 3.5 MMBOE of Bakken and 11.1 MMBOE of Three Forks contingent resources into reserves during the year, and added 63.7 MMBOE and 26.8 MMBOE of contingent resources attributable to the Bakken formation and the Three Forks formations, respectively, as at

December 31, 2014. These contingent resources represent approximately 186 net future drilling locations over and above 83.6 net booked drilling locations identified in the Corporation's booked proved plus probable reserves. These estimates are based primarily upon a drilling density of up to seven wells per drilling spacing unit in the Bakken and Three Forks formations combined. The average expected ultimate recovery per well is estimated at 614 MBOE in this region. These contingent resources are economic using established technologies and under current forecast commodity prices. Given the drilling density to date, these contingent resources represent a non-reserve land utilization of 78% for the Bakken and 73% for the Three Forks formations. All of these contingent resources are classified into "development pending" project maturity subclass as their development is expected to immediately follow the reserves development. The Corporation has approximately 115.4 net wells currently on production in this area. For additional information on the disclosure of contingent resources, including with respect to the presentation of the "best estimate" of contingent resources, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Disclosure of Contingent Resources*".

There is no certainty that it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources". The primary contingencies which currently prevent the classification of the Corporation's disclosed contingent resources associated with the Fort Berthold, North Dakota properties as reserves consist of additional delineation drilling to confirm economic productivity in the undeveloped areas and limitations to development based on adverse topography or other surface restrictions. Significant positive factors related to the estimate include continued advancement of drilling and completion technology, and performance of producing wells continues at expected levels. A significant factor related to the estimate is the limited long-term performance history in the immediate area of the contingent resources. There are a number of inherent risks and contingencies associated with the development of the interests in the property including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on industry partners in project development, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in this Annual Information Form.

U.S. Natural Gas Properties

The Corporation's U.S. natural gas properties primarily consist of its non-operated Marcellus shale gas interests located in northeastern Pennsylvania where the Corporation holds an interest in approximately 55,000 net acres. The Corporation also holds 23,000 net non-core operated acres in West Virginia and Pennsylvania.

The Corporation's U.S. natural gas production averaged 205,212 Mcf/day in 2014, representing approximately 58% of the Corporation's total natural gas production, which includes the effect of curtailments in the second half of the year of approximately 5,000 BOE/day. In general, sales gas infrastructure capacity in the Marcellus region, specifically in northeastern Pennsylvania, is inadequate relative to the amount of natural gas that can be produced in this region, which results in oil and gas producers, including the Corporation, receiving significantly discounted prices. However, infrastructure projects are underway in the region to address these issues, with many projects expected to be completed by the end of 2017. See "*Risk Factors – Lack of adequately developed infrastructure may result in a decline in the Corporation's ability to market oil and natural gas production*".

Proved plus probable U.S. shale gas reserves were 839.9 Bcf as at December 31, 2014, an increase of approximately 40% from year-end 2013 and represented approximately 33% of the Corporation's total proved plus probable reserves.

In 2014, approximately $159 million was invested in the Corporation's interests in the Marcellus. The Corporation participated in the drilling of a total of approximately 18.9 net wells, and a total of approximately 17.3 net wells were brought on- stream. The Corporation currently has 71 net producing wells in the Marcellus, and 15.2 net wells waiting on completions or tie-in.

The Corporation has entered into long-term agreements for the gathering, dehydration, processing, compression and transportation of the Corporation's share of production from its Marcellus properties. These agreements are intended to provide the Corporation with cost certainty and direct ties to the northeastern United States natural gas markets through connections with major interstate pipelines.

CONTINGENT RESOURCES ESTIMATE

NSAI has conducted an independent assessment of the contingent resources attributable to the Corporation's interests in the Marcellus properties and has provided a "best estimate" of economic shale gas contingent resources of approximately 1.4 Tcf at December 31, 2014. Approximately 202.9 Bcf of contingent resources were reclassified as reserves in 2014. The Corporation did see an increase in the contingent resources estimate assigned to its non-operated leases in northeast Pennsylvania due to wells generally outperforming previous forecasts. This resulted in an increase in estimated ultimate recovery per well in most areas. The remaining contingent resources are economic based on the forecast price and cost assumptions used for the Corporation's year-end 2014 reserves evaluations. This estimate represents a non-reserve land utilization rate of 42% and average well production of approximately 9.8 Bcf. These contingent resources are classified into "development pending" project maturity subclass as it is anticipated that their development will be a continuation of the current reserves development.

There is no certainty that it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources". The primary contingencies which currently prevent the classification of the Corporation's disclosed contingent resources associated with its Marcellus interests as reserves consist of additional delineation drilling to confirm economic productivity in the immediate vicinity of the development areas, limitations to development based on adverse topography or other surface restrictions, the uncertainty regarding marketing and transportation of natural gas from development areas, the receipt of all required regulatory permits and approvals to develop the land, and limited access to confidential information of other operators in the Marcellus formation that would support the recognition of reserves on the Corporation's areas of interest. Significant negative factors related to the estimate include: the pace of development, including drilling and infrastructure, is slower than the forecast, risk of adverse regulatory and tax changes, and other issues related to gas development in populated areas. There are a number of inherent risks and contingencies associated with the development of the Corporation's interests in the Marcellus properties including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, acquisitions, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in this Annual Information Form.

For additional information on the disclosure of contingent resources, including with respect to the presentation of the "best estimate" of contingent resources, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Disclosure of Contingent Resources*".

QUARTERLY PRODUCTION HISTORY

The following table sets forth the Corporation's average daily production volumes, on a company interest basis, for each fiscal quarter in 2014 and for the entire year, separately for production in Canada and the United States, and in total.

	Year Ended December 31, 2014				
Country and Product Type	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Light and medium oil (bbls/day)	8,115	8,380	8,154	7,638	**8,071**
Heavy oil (bbls/day)	8,462	8,804	8,683	8,435	**8,596**
Total crude oil (bbls/day)	16,577	17,184	16,837	16,073	**16,667**
Natural gas liquids (bbls/day)	2,540	2,476	2,578	2,315	**2,477**
Total liquids (bbls/day)	19,117	19,660	19,415	18,388	**19,144**
Natural gas (Mcf/day)	151,627	156,401	154,855	140,910	**150,930**
Total Canada (BOE/day)	44,388	45,727	45,224	41,873	**44,299**
United States					
Light and medium oil (bbls/day)	21,183	22,679	23,495	26,745	**23,541**
Natural gas liquids (bbls/day)	722	1,160	1,291	1,172	**1,088**
Total liquids (bbls/day)	21,905	23,839	24,786	27,917	**24,629**
Natural gas (Mcf/day)	15,807	17,547	17,158	17,645	**17,044**
Shale gas (Mcf/day)	179,360	188,981	186,994	197,154	**188,168**
Total United States (BOE/day)	54,433	58,260	58,811	63,718	**58,831**
Total					
Light and medium oil (bbls/day)	29,298	31,059	31,649	34,383	**31,612**
Heavy oil (bbls/day)	8,462	8,804	8,683	8,435	**8,596**
Total crude oil (bbls/day)	37,760	39,863	40,332	42,818	**40,208**
Natural gas liquids (bbls/day)	3,262	3,636	3,869	3,487	**3,565**
Total liquids (bbls/day)	41,022	43,499	44,201	46,305	**43,773**
Natural gas (Mcf/day)	167,434	173,948	172,013	158,555	**167,974**
Shale gas (Mcf/day)	179,360	188,981	186,994	197,154	**188,168**
Total (BOE/day)	98,821	103,987	104,035	105,591	**103,130**

QUARTERLY NETBACK HISTORY

The following tables set forth the Corporation's average netbacks received for each fiscal quarter in 2014 and for the entire year, separately for production in Canada and the United States, and in total. Netbacks are calculated on the basis of prices received before the effects of commodity derivative instruments but after transportation costs, less related royalties and related production costs. For multiple product well types, production costs are entirely attributed to that well's principal product type. As a result, no production costs are attributed to the Corporation's NGLs production as those costs have been attributed to the applicable wells' principal product type.

	Year Ended December 31, 2014				
Light and Medium Crude Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price[(1)]	$ 91.95	$ 99.32	$ 86.46	$ 69.15	**$ 87.02**
Royalties[(2)]	(16.77)	(17.42)	(12.94)	(11.81)	**(14.78)**
Production costs[(3)]	(22.46)	(19.76)	(20.06)	(22.03)	**(21.05)**
Netback	$ 52.72	$ 62.14	$ 53.46	$ 35.31	**$ 51.19**
United States					
Sales price[(1)]	$ 95.74	$ 96.41	$ 89.63	$ 67.12	**$ 86.17**
Royalties[(2)]	(27.70)	(27.09)	(25.73)	(19.60)	**(24.74)**
Production costs[(3)]	(8.68)	(10.39)	(10.34)	(10.43)	**(10.01)**
Netback	$ 59.36	$ 58.93	$ 53.56	$ 37.09	**$ 51.42**
Total					
Sales price[(1)]	$ 94.69	$ 97.20	$ 88.81	$ 67.57	**$ 86.39**
Royalties[(2)]	(24.67)	(24.48)	(22.44)	(17.87)	**(22.19)**
Production costs[(3)]	(12.50)	(12.92)	(12.84)	(13.01)	**(12.83)**
Netback	$ 57.52	$ 59.80	$ 53.53	$ 36.69	**$ 51.37**

	Year Ended December 31, 2014				
Heavy Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada/Total					
Sales price[(1)]	$ 80.37	$ 86.79	$ 78.03	$ 65.33	**$ 77.69**
Royalties[(2)]	(18.08)	(20.83)	(17.95)	(15.68)	**(18.16)**
Production costs[(3)]	(18.13)	(19.47)	(20.99)	(21.55)	**(20.05)**
Netback	$ 44.16	$ 46.49	$ 39.09	$ 28.10	**$ 39.48**

Natural Gas Liquids ($ per bbl)	Year Ended December 31, 2014 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Canada					
Sales price(1)	$ 69.23	$ 57.01	$ 46.28	$ 48.67	**$ 55.32**
Royalties(2)	(18.79)	(14.34)	(11.79)	(12.45)	**(14.35)**
Production costs(3)	–	–	–	–	**–**
Netback	$ 50.44	$ 42.67	$ 34.49	$ 36.22	**$ 40.97**
United States					
Sales price(1)	$ 56.02	$ 35.00	$ 42.01	$ 23.94	**$ 37.53**
Royalties(2)	(10.84)	(7.41)	(8.62)	(16.47)	**(10.80)**
Production costs(3)	–	–	–	–	**–**
Netback	$ 45.18	$ 27.59	$ 33.39	$ 7.47	**$ 26.73**
Total					
Sales price(1)	$ 66.30	$ 49.98	$ 44.85	$ 40.36	**$ 49.89**
Royalties(2)	(17.03)	(12.13)	(10.73)	(13.80)	**(13.27)**
Production costs(3)	–	–	–	–	**–**
Netback	$ 49.27	$ 37.85	$ 34.12	$ 26.56	**$ 36.62**

Natural Gas ($ per Mcf)	Year Ended December 31, 2014 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Canada					
Sales price(1)	$ 5.11	$ 4.32	$ 3.82	$ 3.54	**$ 4.20**
Royalties(2)	(0.42)	(0.27)	(0.19)	(0.18)	**(0.26)**
Production costs(3)	(2.34)	(2.20)	(2.31)	(2.55)	**(2.35)**
Netback	$ 2.35	$ 1.85	$ 1.32	$ 0.81	**$ 1.59**
United States					
Sales price(1)	$ 8.32	$ 7.43	$ 5.21	$ 4.65	**$ 6.34**
Royalties(2)	(1.95)	(1.84)	(1.28)	(1.28)	**(1.58)**
Production costs(3)	–	–	–	–	**–**
Netback	$ 6.37	$ 5.59	$ 3.93	$ 3.37	**$ 4.76**
Total					
Sales price(1)	$ 5.41	$ 4.63	$ 3.96	$ 3.66	**$ 4.42**
Royalties(2)	(0.56)	(0.43)	(0.30)	(0.30)	**(0.40)**
Production costs(3)	(2.12)	(1.98)	(2.08)	(2.26)	**(2.11)**
Netback	$ 2.73	$ 2.22	$ 1.58	$ 1.10	**$ 1.91**

Shale Gas ($ per Mcf)	Year Ended December 31, 2014 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
United States/Total					
Sales price(1)	$ 4.48	$ 3.46	$ 2.55	$ 2.68	**$ 3.26**
Royalties(2)	(0.92)	(0.75)	(0.63)	(0.61)	**(0.72)**
Production costs(3)	(0.64)	(0.70)	(0.87)	(0.83)	**(0.76)**
Netback	$ 2.92	$ 2.01	$ 1.05	$ 1.24	**$ 1.78**

Total ($ per BOE)		First Quarter		Second Quarter		Third Quarter		Fourth Quarter		Annual
	Year Ended December 31, 2014									
Canada										
Sales price(1)	$	53.60	$	52.90	$	46.41	$	40.48	**$**	**48.44**
Royalties(2)		(9.02)		(8.90)		(7.11)		(6.60)		**(7.92)**
Production costs(3)		(15.56)		(14.91)		(15.55)		(16.93)		**(15.72)**
Netback	$	29.02	$	29.09	$	23.75	$	16.95	**$**	**24.80**
United States										
Sales price(1)	$	55.19	$	51.69	$	46.35	$	38.18	**$**	**47.45**
Royalties(2)		(14.52)		(13.69)		(12.86)		(10.80)		**(12.88)**
Production costs(3)		(5.49)		(6.32)		(6.91)		(6.93)		**(6.45)**
Netback	$	35.18	$	31.68	$	26.58	$	20.45	**$**	**28.12**
Total										
Sales price(1)	$	54.19	$	51.93	$	46.13	$	38.83	**$**	**47.61**
Royalties(2)		(12.05)		(11.58)		(10.36)		(9.13)		**(10.75)**
Production costs(3)		(10.02)		(10.09)		(10.67)		(10.90)		**(10.43)**
Netback	$	32.12	$	30.26	$	25.10	$	18.80	**$**	**26.43**

Notes:

(1) Net of transportation costs but before the effects of commodity derivative instruments.

(2) Includes production taxes.

(3) Production costs are costs incurred to operate and maintain wells and related equipment and facilities, including operating costs of support equipment used in oil and gas activities and other costs of operating and maintaining those wells and related equipment and facilities. Examples of production costs include items such as field staff labour costs, costs of materials, supplies and fuel consumed and supplies utilized in operating the wells and related equipment (such as power (including gains and losses on electricity contracts), chemicals and lease rentals), repairs and maintenance costs, property taxes, insurance costs, costs of workovers, net processing and treating fees, overhead fees, taxes (other than income, capital, withholding or U.S. state production taxes) and other costs.

ABANDONMENT AND RECLAMATION COSTS

In connection with its operations, the Corporation will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The Corporation budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. The Corporation estimates such costs through a model that incorporates data from the Corporation's operating history, industry sources and cost formulas used by Alberta Energy Regulator ("**AER**"), together with other operating assumptions. The Corporation expects all of its net wells to incur these costs. The Corporation estimates the total amount of such costs, net of estimated salvage value for such equipment, to be approximately $731 million on an undiscounted basis and $144 million discounted at 10%. The calculations of future net revenue associated with proved plus probable reserves under *"Oil and Natural Gas Reserves"* in this Annual Information Form exclude approximately $507 million on an undiscounted basis and $84 million discounted at 10% as these amounts represent costs for abandonment and reclamation of facilities and wells for which no reserves have been attributed. In the next three financial years, the Corporation anticipates that a total of approximately $77 million on an undiscounted basis and $66 million discounted at 10% will be incurred in respect of abandonment and reclamation costs.

TAX HORIZON

The Corporation is subject to standard applicable corporate income taxes. Within the context of current commodity prices and capital spending plans, the Corporation expects to pay U.S. cash taxes of less than 1% of U.S. cash flow in 2015 and no cash taxes in Canada. U.S. cash tax is mainly comprised of Alternative Minimum Tax ("AMT") which is recoverable against regular income taxes payable in the future. These estimates may vary depending on numerous factors, including fluctuations in commodity prices, and the Corporation's capital spending, changes in governing tax laws, and the nature and timing of the Corporation's acquisitions and dispositions. If crude oil and natural gas prices were to strengthen beyond the levels anticipated by the current forward market, the Corporation's tax pools, including the AMT credit, would be utilized more quickly and it may experience higher than expected cash taxes or payment of such taxes in an earlier time period, including regular U.S. income taxes. As a result, the Corporation emphasizes that it is difficult to give guidance on future taxability as it operates within an industry that constantly changes. See "*Risk Factors – Changes in laws, including those affecting tax, royalties and other financial matters, and interpretations of those laws, may adversely affect the Corporation and its securityholders*".

For additional information, see Notes 2(g) and 14 to the Corporation's audited consolidated financial statements for the year ended December 31, 2014 and the information under the heading "Taxes" in the Corporation's MD&A for the year ended December 31, 2014.

MARKETING ARRANGEMENTS AND FORWARD CONTRACTS

Crude Oil and NGLs

The Corporation's crude oil and NGLs production is marketed to a diverse portfolio of intermediaries and end users generally on 30-day continuously renewing contracts for crude oil and yearly contracts for NGLs whose terms fluctuate with the monthly spot markets. The Corporation received an average price (net of transportation costs but before the effects of commodity derivative instruments) of $86.39/bbl for its light and medium crude oil, $77.69/bbl for its heavy crude oil and $49.89/bbl for its NGLs for the year ended December 31, 2014, compared to $88.27/bbl for its light and medium crude oil, $69.07/bbl for its heavy crude oil and $52.25/bbl for its NGLs for the year ended December 31, 2013.

In Canada, the Corporation typically transports its Canadian crude oil production to its buyers by pipeline or truck. The Corporation may also sell a portion of its crude oil production to buyers who may utilize rail transportation after title is transferred into the buyer's name. The Corporation has field gathering transportation agreements for its production in Saskatchewan for approximately 2,200 bbls/day in 2015, and approximately 1,500 bbls/day in 2016. The Corporation also has approximately 900 BOE/day of pipeline transportation agreements in place for 2015 to 2026 for its Alberta crude oil and condensate production. The Corporation typically sells its NGLs production under one-year contracts at floating index-based prices. The Corporation has also contracted NGLs pipeline transportation agreements for an average of approximately 150 BOE/day through 2018, and has entered into firm NGLs fractionation contracts for 900 BOE/day through 2015, increasing to 1,200 BOE/day through 2025.

In the United States, the Corporation sells its crude oil production generally under negotiated 30-day contracts at floating index-based prices. The Corporation transports its U.S. crude oil production to its buyers by pipeline and/or truck, and also sells a portion of its crude oil production to buyers who may utilize rail transportation after title is transferred into the buyer's name. The Corporation currently has a mix of up to 16,000 bbls/day of firm sales and transportation contracts through 2017 for its U.S. oil production. In addition, the Corporation has entered into an agreement for firm capacity for five years on the Enbridge Sandpiper crude oil pipeline project for 5,000 bbls/day. This project is currently pending regulatory approval with an expected in-service date of 2017 to 2018. The Corporation's NGLs associated with its U.S. crude oil production volumes are marketed on its behalf by midstream companies in North Dakota and Montana.

Natural Gas

In marketing its natural gas production, the Corporation strives for a mix of contracts and customers. In Canada, the Corporation sells its natural gas production at a mix of fixed and floating prices for a variety of terms ranging from spot sales to one year or longer. The Corporation's monthly sales portfolio reflected a mix of the daily and monthly AECO market indices, as well as the basis differential to NYMEX gas prices in 2014. Approximately 42% of the Corporation's total natural gas production originated in Canada in 2014 and received an average price of $4.20/Mcf during the year. The Corporation holds firm service contracts on 182 MMcf/day of receipt capacity onto natural gas pipelines in Canada as of January 2015, of which approximately 15 MMcf/day is exported out of Western Canada.

Approximately 58% of the Corporation's natural gas production originated in the United States. The Corporation delivered approximately 57% of its Marcellus production in 2014 onto the Transco Leidy Pipeline, with the remaining volumes delivered onto the Tennessee Gas Pipeline 300 Line, in Pennsylvania. The Corporation has firm "must-take" sales contracts for an average of approximately 47 MMcf/day of natural gas production in the Marcellus through 2026 (with quantities ranging between 35 MMcf/day to 70 MMcf/day in any given year) with buyers holding pipeline capacity on these and other pipelines in the region. The Corporation also has in place firm transportation agreements for approximately 12 MMcf/day, with the majority of that capacity expiring in 2033. In addition, the Corporation has entered into a binding contract for five years of firm transportation capacity for 30 MMcf/day on the PennEast pipeline project. This project is currently pending regulatory approval with an expected in-service date of 2018. The Corporation received an average price for its U.S. Marcellus natural gas production of US$2.96/Mcf. Approximately 8% of the Corporation's U.S. natural gas production was associated natural gas production from its crude oil operations in North Dakota and Montana. The Corporation does not market these volumes directly, as they are marketed on our behalf by midstream companies. The Corporation received US$5.74/Mcf for this production in 2014 because of the high heat content of the natural gas due to associated liquids.

The Corporation's percentage of 2014 revenues attributable to natural gas (net of transportation costs but before the effects of commodity derivative instruments) was 28% compared to 22% in 2013. The average price received by the Corporation (net of transportation costs but before the effects of commodity derivative instruments) for its natural gas in 2014 was $3.81/Mcf compared to $3.26/Mcf for the year ended December 31, 2013.

Future Commitments and Forward Contracts

The Corporation may use various types of derivative financial instruments and fixed price physical sales contracts to manage the risk related to fluctuating commodity prices. Absent such hedging activities, all of the crude oil and NGLs and the majority of natural gas production of the Corporation is sold into the open market at prevailing market prices, which exposes the Corporation to the risks associated with commodity price fluctuations and foreign exchange rates. See "*Risk Factors*". Information regarding the Corporation's financial instruments is contained in Note 16 to the Corporation's audited consolidated financial statements for the year ended December 31, 2014 and under the headings "*Results of Operations – Pricing*" and "*Results of Operations – Price Risk Management*" in the Corporation's MD&A for the year ended December 31, 2014, each of which is available through the internet on the Corporation's website at www.enerplus.com, on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

Oil and Natural Gas Reserves

SUMMARY OF RESERVES

All of the Corporation's reserves, including its U.S. reserves, have been evaluated in accordance with NI 51-101. Independent reserves evaluations have been conducted on properties comprising approximately 89% of the Corporation's total proved plus probable reserves value (discounted at 10%, using forecast prices and costs). McDaniel, an independent petroleum consulting firm based in Calgary, Alberta, has evaluated properties which comprise approximately 71% of the net present value (discounted at 10%, using forecast prices and costs) of the Corporation's proved plus probable reserves located in Canada and all of the Corporation's reserves associated with the Corporation's properties located in North Dakota and Montana. The Corporation has evaluated the balance of its Canadian properties using similar evaluation parameters, including the same forecast price, inflation and exchange rate assumptions utilized by McDaniel. McDaniel has reviewed the Corporation's internal evaluation of these properties.

NSAI, independent petroleum consultants based in Dallas, Texas, has evaluated all of the Corporation's reserves associated with the Corporation's properties in Pennsylvania and West Virginia. For consistency in the Corporation's reserves reporting, NSAI used McDaniel's January 1, 2015 forecast prices and inflation rates to prepare its report. The Corporation used McDaniel's forecast exchange rates set forth below to convert U.S. dollar amounts in the NSAI Report to Canadian dollar amounts for presentation in this Annual Information Form.

The following sections and tables summarize, as at December 31, 2014, the Corporation's oil, NGLs, natural gas and shale gas reserves and the estimated net present values of future net revenues associated with such reserves, together with certain information, estimates and assumptions associated with such reserve estimates. The data contained in the tables is a summary of the evaluations, and as a result the tables may contain slightly different numbers than the evaluations themselves due to rounding. Additionally, the columns and rows in the tables may not add due to rounding. For information relating to the changes in the volumes of the Corporation's reserves from December 31, 2013 to December 31, 2014, see "– *Reconciliation of Reserves*" below.

All estimates of future net revenues are stated prior to provision for interest and general and administrative expenses and after deduction of royalties and estimated future capital expenditures, and are presented both before and after deducting income taxes. For additional information, see "*Business of the Corporation – Tax Horizon*", "*Industry Conditions*" and "*Risk Factors*" in this Annual Information Form.

With respect to pricing information in the following reserves information, the wellhead oil prices were adjusted for quality and transportation based on historical actual prices. The natural gas prices were adjusted, where necessary, based on historical pricing based on heating values and transportation. The NGLs prices were adjusted to reflect historical average prices received.

It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of the Corporation's crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Presentation of Oil and Gas Reserves, Resources and Production Information*" in conjunction with the following tables and notes.

The following tables set forth the estimated gross and net reserves volumes and net present value of future net revenue attributable to the Corporation's reserves at December 31, 2014, using forecast price and cost cases. The Corporation has also previously publicly disclosed its reserves on a "company interest" basis (being the gross volumes plus the Corporation's share of royalty interests in reserves), which results in an additional 2.0 MMBOE of proved plus probable reserves attributed to the Corporation. "Company interest" is not a term defined in NI 51-101 and therefore may not be comparable to reserves estimates disclosed by other issuers in accordance with NI 51-101. Following the disposition of its interests in Jonah properties in 2014, the Corporation no longer discloses its reserves on a "company interest" basis.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)
As of December 31, 2014

	Oil and Natural Gas Reserves											
	Light & Medium Oil		Heavy Oil		Natural Gas Liquids		Natural Gas		Shale Gas		Total	
Reserves Category	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)
Proved Developed Producing												
Canada	21,392	18,840	26,858	21,454	3,820	2,829	219,631	199,139	–	–	88,675	76,313
United States	46,969	38,067	–	–	2,329	1,869	48,759	40,055	386,620	309,371	121,861	98,173
Total	**68,361**	**56,907**	**26,858**	**21,454**	**6,149**	**4,698**	**268,390**	**239,194**	**386,620**	**309,371**	**210,536**	**174,486**
Proved Developed Non-Producing												
Canada	232	198	13	12	101	71	6,885	5,418	–	–	1,493	1,183
United States	5,277	4,180	–	–	355	281	2,955	2,341	70,010	56,014	17,793	14,187
Total	**5,509**	**4,378**	**13**	**12**	**456**	**352**	**9,840**	**7,759**	**70,010**	**56,014**	**19,286**	**15,370**
Proved Undeveloped												
Canada	4,947	4,160	4,651	3,532	412	310	44,145	41,055	–	–	17,368	14,844
United States	16,668	13,362	–	–	1,120	898	9,334	7,483	107,952	86,384	37,336	29,904
Total	**21,615**	**17,522**	**4,651**	**3,532**	**1,532**	**1,208**	**53,479**	**48,538**	**107,952**	**86,384**	**54,704**	**44,748**
Total Proved												
Canada	26,571	23,197	31,522	24,998	4,333	3,209	270,661	245,613	–	–	107,535	92,340
United States	68,914	55,609	–	–	3,804	3,047	61,048	49,878	564,583	451,770	176,990	142,264
Total	**95,485**	**78,806**	**31,522**	**24,998**	**8,137**	**6,256**	**331,709**	**295,491**	**564,583**	**451,770**	**284,525**	**234,604**
Probable												
Canada	9,177	7,674	11,616	8,966	1,330	968	89,359	81,362	–	–	37,016	31,168
United States	52,631	42,243	–	–	3,332	2,668	35,362	28,571	275,357	220,305	107,749	86,390
Total	**61,808**	**49,917**	**11,616**	**8,966**	**4,662**	**3,636**	**124,721**	**109,933**	**275,357**	**220,305**	**144,766**	**117,558**
Total Proved Plus Probable												
Canada	35,748	30,871	43,138	33,964	5,662	4,177	360,020	326,975	–	–	144,552	123,507
United States	121,545	97,852	–	–	7,136	5,715	96,410	78,449	839,940	672,075	284,739	228,654
Total	**157,293**	**128,723**	**43,138**	**33,964**	**12,798**	**9,892**	**456,430**	**405,424**	**839,940**	**672,075**	**429,291**	**352,161**

Summary of Net Present Value of Future Net Revenue
Attributable to Oil and Gas Reserves (Forecast Prices and Costs)
As of December 31, 2014

	Net Present Value of Future Net Revenue Discounted at (%/Year)										
	Before Deducting Income Taxes					After Deducting Income Taxes					Unit
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**Value[1]**
					(in $ millions)						($/BOE)
Proved Developed Producing											
Canada	2,031	1,449	1,125	923	787	1,860	1,368	1,083	900	773	$14.74
United States	3,245	2,145	1,620	1,318	1,123	2,560	1,762	1,371	1,142	990	$16.50
Total	**5,276**	**3,594**	**2,745**	**2,241**	**1,910**	**4,420**	**3,130**	**2,454**	**2,042**	**1,763**	**$15.73**
Proved Developed Non-Producing											
Canada	41	20	13	10	8	31	16	11	8	7	$10.99
United States	349	186	116	78	54	209	111	69	47	33	$8.18
Total	**390**	**206**	**129**	**88**	**62**	**240**	**127**	**80**	**55**	**40**	**$8.39**
Proved Undeveloped											
Canada	482	229	116	57	22	361	168	82	36	8	$7.81
United States	774	283	92	(3)	(58)	465	157	34	(27)	(63)	$3.08
Total	**1,256**	**512**	**208**	**54**	**(36)**	**826**	**325**	**116**	**9**	**(55)**	**$4.65**
Total Proved											
Canada	2,554	1,698	1,254	990	816	2,252	1,552	1,175	944	788	$13.58
United States	4,369	2,614	1,828	1,393	1,120	3,234	2,031	1,474	1,161	960	$12.85
Total	**6,923**	**4,312**	**3,082**	**2,383**	**1,936**	**5,486**	**3,583**	**2,649**	**2,105**	**1,748**	**$13.14**
Probable											
Canada	1,398	657	405	286	219	1,045	495	308	220	170	$12.99
United States	3,613	1,583	869	536	351	2,168	940	500	298	188	$10.06
Total	**5,011**	**2,240**	**1,274**	**822**	**570**	**3,213**	**1,435**	**808**	**518**	**358**	**$10.84**
Total Proved Plus Probable											
Canada	3,952	2,355	1,659	1,276	1,035	3,297	2,047	1,483	1,164	958	$13.43
United States	7,982	4,197	2,697	1,929	1,471	5,402	2,971	1,974	1,459	1,148	$11.80
Total	**11,934**	**6,552**	**4,356**	**3,205**	**2,506**	**8,699**	**5,018**	**3,457**	**2,623**	**2,106**	**$12.37**

Note:

(1) Calculated using net present value of future net revenue before deducting income taxes, discounted at 10% per year, and net reserves. The unit values are based on net reserves volumes.

FORECAST PRICES AND COSTS

The forecast price and cost case assumes no legislative or regulatory amendments, and includes the effects of inflation. The estimated future net revenue to be derived from the production of the reserves includes the following price forecasts supplied by McDaniel as of January 1, 2015 (and utilized by NSAI and by the Corporation in its internal evaluations for consistency in the Corporation's reserves reporting) and the following inflation and exchange rate assumptions:

	Crude Oil				Natural Gas		Natural Gas Liquids				
							Edmonton Par Price				
Year	**WTI[1]**	**Edmonton Light[2]**	**Alberta Heavy[3]**	**Sask Cromer Medium[4]**	**Alberta AECO Spot Price**	**U.S. Henry Hub Gas Price**	**Propane**	**Butanes**	**Condensate & Natural Gasolines**	**Inflation Rate**	**Exchange Rate**
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/MMbtu)	($US/MMbtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	(%/year)	($US/$Cdn)
2015	65.00	68.60	51.10	64.50	3.50	3.30	26.10	52.80	72.60	2.0	0.860
2016	75.00	83.20	62.00	78.20	4.00	3.80	36.50	67.00	87.30	2.0	0.860
2017	80.00	88.90	66.20	83.60	4.25	4.05	44.50	71.60	93.10	2.0	0.860
2018	84.90	94.60	70.50	88.90	4.50	4.30	49.30	76.20	98.80	2.0	0.860
2019	89.30	99.60	74.20	93.60	4.70	4.55	51.80	80.30	103.90	2.0	0.860
Thereafter	(5)	(5)	(5)	(5)	(6)	(6)	(5)	(5)	(5)		0.860

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40° API/0.5% sulphur.
(2) Edmonton Light Sweet 40° API/0.3% sulphur.
(3) Heavy Crude Oil 12° API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).
(4) Midale Cromer Crude Oil 29° API/2.0% sulphur.
(5) Escalation is approximately 5% in 2020 and 2% per year thereafter.
(6) Escalation is approximately 6.5% in 2020, declining to 3.5% in 2024 and approximately 2% per year thereafter.

In 2014, the Corporation received a weighted average price (net of transportation costs but before hedging) of $77.69/bbl for heavy crude oil, $86.39/bbl for light and medium crude oil, $49.89/bbl for NGLs and $4.42/Mcf for natural gas and $3.26/Mcf for shale gas.

UNDISCOUNTED FUTURE NET REVENUE BY RESERVES CATEGORY

The undiscounted total future net revenue by reserves category as of December 31, 2014, using forecast prices and costs, is set forth below (columns or rows may not add due to rounding):

Reserves Category	Revenue	Royalties and Production Taxes	Operating Costs	Develop-ment Costs	Abandon-ment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
				(in $ millions)				
Proved Reserves								
Canada	7,188	1,137	2,955	367	175	2,554	302	2,252
United States	10,575	2,723	2,789	639	55	4,369	1,135	3,234
Total	17,763	3,860	5,744	1,006	230	6,923	1,437	5,486
Proved Plus Probable Reserves								
Canada	10,429	1,712	4,169	409	187	3,952	655	3,297
United States	18,652	4,863	4,213	1,527	66	7,982	2,580	5,402
Total	29,081	6,576	8,382	1,936	253	11,934	3,235	8,699

NET PRESENT VALUE OF FUTURE NET REVENUE BY RESERVES CATEGORY AND PRODUCTION GROUP

The net present value of future net revenue before income taxes by reserves category and production group as of December 31, 2014, using forecast prices and costs and discounted at 10% per year, is set forth below:

Reserves Category	Production Group	Net Present Value of Future Net Revenue Before Income Taxes (Discounted at 10%/year)	Unit Value[3]
		(in $ millions)	($/bbl/$/Mcf)
Canada			
Proved Reserves	Light and Medium Crude Oil[1]	513	$22.25
	Heavy Oil[1]	527	$21.08
	Natural Gas[2]	214	$0.99
	Shale Gas[4]	n/a	n/a
	Total	1,254	
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	644	$20.97
	Heavy Oil[1]	686	$20.21
	Natural Gas[2]	329	$1.15
	Shale Gas[4]	n/a	n/a
	Total	1,659	
United States			
Proved Reserves	Light and Medium Crude Oil[1]	1,285	$23.12
	Heavy Oil[1]	n/a	n/a
	Natural Gas[2]	n/a	n/a
	Shale Gas[4]	542	$1.20
	Total	1,828	
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	2,027	$20.71
	Heavy Oil[1]	n/a	n/a
	Natural Gas[2]	n/a	n/a
	Shale Gas[4]	670	$1.00
	Total	2,697	
Total			
Proved Reserves	Light and Medium Crude Oil[1]	1,799	$22.86
	Heavy Oil[1]	527	$21.08
	Natural Gas[2]	214	$0.99
	Shale Gas[4]	542	$1.20
	Total	3,082	
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	2,671	$20.77
	Heavy Oil[1]	686	$20.21
	Natural Gas[2]	329	$1.15
	Shale Gas[4]	670	$1.00
	Total	4,356	

Notes:

(1) Including net present value of solution gas and other by-products.
(2) Including net present value of by-products, but excluding solution gas and by-products from oil wells.
(3) Calculated using net oil or net gas reserves and forecast price and cost assumptions.
(4) No NGLs are associated with Shale Gas.

ESTIMATED PRODUCTION FOR GROSS RESERVES ESTIMATES

The volume of total production for the Corporation estimated for 2015 in preparing the estimates of gross proved reserves and gross probable reserves is set forth below. Actual 2015 production (including from the Fort Berthold property in the separate table below) may vary from the estimates provided by McDaniel and NSAI as the Corporation's actual development programs, timing and priorities may differ from the forecast of development by McDaniel and NSAI. Columns may not add due to rounding.

	Gross Proved Reserves							
	Canada				United States			
Product Type	Estimated 2015 Aggregate Production		Estimated 2015 Average Daily Production		Estimated 2015 Aggregate Production		Estimated 2015 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	2,515	Mbbls	6,890	bbls/day	8,688	Mbbls	23,803	bbls/day
Heavy Oil	3,445	Mbbls	9,438	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	5,960	Mbbls	16,328	bbls/day	8,688	Mbbls	23,803	bbls/day
Natural Gas Liquids	597	Mbbls	1,636	bbls/day	499	Mbbls	1,367	bbls/day
Total Liquids	6,557	Mbbls	17,964	bbls/day	9,187	Mbbls	25,170	bbls/day
Natural Gas	45,196	MMcf	123,824	Mcf/day	7,123	MMcf	19,514	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	73,160	MMcf	200,439	Mcf/day
Total	14,089	MBOE	38,601	BOE/day	22,567	MBOE	61,830	BOE/day

	Gross Probable Reserves							
	Canada				United States			
Product Type	Estimated 2015 Aggregate Production		Estimated 2015 Average Daily Production		Estimated 2015 Aggregate Production		Estimated 2015 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	182	Mbbls	498	bbls/day	1,797	Mbbls	4,924	bbls/day
Heavy Oil	221	Mbbls	606	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	403	Mbbls	1,104	bbls/day	1,797	Mbbls	4,924	bbls/day
Natural Gas Liquids	47	Mbbls	130	bbls/day	120	Mbbls	328	bbls/day
Total Liquids	451	Mbbls	1,234	bbls/day	1,917	Mbbls	5,252	bbls/day
Natural Gas	3,211	MMcf	8,798	Mcf/day	1,066	MMcf	2,921	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	2,924	MMcf	8,012	Mcf/day
Total	986	MBOE	2,701	BOE/day	2,582	MBOE	7,074	BOE/day

All references to "Shale Gas" under "United States" in the "Gross Proved Reserves" and "Gross Probable Reserves" tables above, represent estimated 2015 production from the Marcellus field in Northeast Pennsylvania, United States, which is estimated to account for more than 20% of the Corporation's 2015 production. In addition, the following table sets forth McDaniel's estimated 2015 production for the Corporation's Fort Berthold property located in North Dakota, United States, as this field is estimated to account for more than 20% of the above estimate of the Corporation's 2015 production.

	Estimated 2015 Production for Fort Berthold Property							
	Gross Proved Reserves				Gross Probable Reserves			
Product Type	Estimated 2015 Aggregate Production		Estimated 2015 Average Daily Production		Estimated 2015 Aggregate Production		Estimated 2015 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	7,314	Mbbls	20,038	bbls/day	1,766	Mbbls	4,838	bbls/day
Heavy Oil	–	Mbbls	–	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	7,314	Mbbls	20,038	bbls/day	1,766	Mbbls	4,838	bbls/day
Natural Gas Liquids	499	Mbbls	1,368	bbls/day	120	Mbbls	328	bbls/day
Total Liquids	7,813	Mbbls	21,406	bbls/day	1,886	Mbbls	5,166	bbls/day
Natural Gas	4,161	MMcf	11,401	Mcf/day	998	MMcf	2,735	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	–	MMcf	–	Mcf/day
Total	8,507	MBOE	23,306	BOE/day	2,052	MBOE	5,622	BOE/day

FUTURE DEVELOPMENT COSTS

The amount of development costs deducted in the estimation of net present value of future net revenue is set forth below. The Corporation intends to fund its development activities through internally generated cash flow and debt. The Corporation does not anticipate that the cost of obtaining the funds required for these development activities will have a material effect on the Corporation's disclosed oil and gas reserves or future net revenue attributable to those reserves. For additional information, see "*Business of the Corporation – Capital Expenditures and Costs Incurred*".

	Canada				United States			
	Proved Reserves		Proved Plus Probable Reserves		Proved Reserves		Proved Plus Probable Reserves	
Year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year
				(in $ millions)				
2015	112	108	125	120	317	302	438	417
2016	127	111	131	114	121	105	308	267
2017	48	39	66	53	179	141	357	281
2018	32	24	36	27	8	6	310	222
2019	15	10	19	13	14	9	114	74
Remainder	33	18	32	17	–	–	–	–
Total	367	310	409	344	639	563	1,527	1,262

RECONCILIATION OF RESERVES

Overview

The Corporation's total gross proved plus probable reserves at December 31, 2014 were approximately 429.3 MMBOE, up approximately 7% from year-end 2013. The Corporation's gross proved plus probable oil and NGLs reserves were at 213.2 MMBOE and represent approximately 50% of total proved plus probable gross reserves, down from 52% at year-end 2013. The Corporation replaced approximately 163% of its 2014 gross production through its exploration and development program, adding 60.8 MMBOE of proved plus probable reserves. Approximately 31% of the additions were oil and NGLs, representing the replacement of 119% of the Corporation's 2014 oil and NGLs production. The largest amount of crude oil reserves additions was in the Corporation's Fort Berthold crude oil property in North Dakota. The largest amount of natural gas additions was in the Marcellus shale gas property, as a result of development activities. The Corporation sold 10.9 MMBOE of proved plus probable reserves in 2014, all of which were associated with the disposition of the Corporation's non-core assets. As a result of the weak outlook for natural gas prices, approximately 31.2 BcfGE of natural gas reserves were removed from the Corporation's reserves at year-end. Total proved plus probable natural gas reserves, excluding shale gas, decreased by approximately 19% from year-end 2013. Total proved plus probable natural gas reserves, including shale gas reserves, increased by approximately 11% from year-end 2013.

The following tables reconcile the Corporation's gross oil and natural gas reserves from December 31, 2013 to December 31, 2014, by country and in total, using forecast prices and costs. Certain columns may not add due to rounding.

CANADIAN OIL AND GAS RESERVES

Canada	Light & Medium Oil			Heavy Oil			Natural Gas Liquids		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2013	29,163	9,662	38,825	30,806	11,260	42,066	6,203	2,523	8,726
Acquisitions	–	–	–	–	–	–	–	–	–
Dispositions	(24)	(10)	(34)	–	–	–	(1,425)	(469)	(1,894)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	612	258	870	2,265	1,884	4,149	533	165	698
Economic Factors	200	–	200	–	–	–	(5)	(566)	(571)
Technical Revisions	(451)	(733)	(1,183)	1,587	(1,528)	59	(114)	(323)	(437)
Production	(2,930)	–	(2,930)	(3,136)	–	(3,136)	(860)	–	(860)
December 31, 2014	**26,571**	**9,177**	**35,748**	**31,522**	**11,616**	**43,138**	**4,333**	**1,330**	**5,662**

Canada	Associated and Non-Associated Gas (Natural Gas)			Shale Gas			Total		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2013	336,199	142,103	478,302	–	–	–	122,204	47,129	169,334
Acquisitions	–	–	–	–	–	–	–	–	–
Dispositions	(41,034)	(13,075)	(54,108)	–	–	–	(8,288)	(2,658)	(10,946)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	28,208	12,484	40,692	–	–	–	8,112	4,387	12,499
Economic Factors	(8,200)	(20,847)	(29,047)	–	–	–	(1,171)	(4,041)	(5,212)
Technical Revisions	8,604	(31,307)	(22,703)	–	–	–	2,456	(7,801)	(5,345)
Production	(53,116)	–	(53,116)	–	–	–	(15,778)	–	(15,778)
December 31, 2014	**270,661**	**89,359**	**360,020**	**–**	**–**	**–**	**107,535**	**37,016**	**144,552**

UNITED STATES OIL AND GAS RESERVES

United States	Light & Medium Oil			Heavy Oil			Natural Gas Liquids		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2013	58,526	52,678	111,204	–	–	–	2,529	3,106	5,635
Acquisitions	64	995	1,059	–	–	–	4	67	71
Dispositions	–	–	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	8,243	4,157	12,400	–	–	–	586	291	876
Economic Factors	7	–	7	–	–	–	–	–	–
Technical Revisions	10,651	(5,199)	5,452	–	–	–	1,078	(132)	946
Production	(8,577)	–	(8,577)	–	–	–	(393)	–	(393)
December 31, 2014	**68,914**	**52,631**	**121,545**	**–**	**–**	**–**	**3,804**	**3,332**	**7,136**

(continued)

United States	Associated and Non-Associated Gas (Natural Gas)			Shale Gas			Total		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2013	54,081	32,342	86,423	411,431	189,430	600,861	138,640	92,746	231,386
Acquisitions	36	557	593	–	–	–	74	1,154	1,229
Dispositions	–	–	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	4,879	2,421	7,301	164,065	38,835	202,900	36,986	11,324	48,310
Economic Factors	13	–	13	–	–	–	9	–	9
Technical Revisions	8,067	42	8,109	57,767	47,092	104,859	22,702	2,525	25,227
Production	(6,028)	–	(6,028)	(68,681)	–	(68,681)	(21,422)	–	(21,422)
December 31, 2014	**61,048**	**35,362**	**96,410**	**564,583**	**275,357**	**839,940**	**176,990**	**107,749**	**284,739**

TOTAL OIL AND GAS RESERVES

Total	Light & Medium Oil			Heavy Oil			Natural Gas Liquids		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2013	87,689	62,340	150,029	30,806	11,260	42,066	8,732	5,629	14,360
Acquisitions	64	995	1,059	–	–	–	4	67	71
Dispositions	(24)	(10)	(34)	–	–	–	(1,425)	(469)	(1,894)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	8,855	4,415	13,271	2,265	1,884	4,149	1,119	455	1,574
Economic Factors	207	–	207	–	–	–	(5)	(566)	(571)
Technical Revisions	10,200	(5,932)	4,268	1,587	(1,528)	59	964	(455)	510
Production	(11,507)	–	(11,507)	(3,136)	–	(3,136)	(1,253)	–	(1,253)
December 31, 2014	**95,485**	**61,808**	**157,293**	**31,522**	**11,616**	**43,138**	**8,137**	**4,662**	**12,798**

Total	Associated and Non-Associated Gas (Natural Gas)			Shale Gas			Total		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2013	390,279	174,446	564,725	411,431	189,430	600,861	260,844	139,875	400,720
Acquisitions	36	557	593	–	–	–	74	1,154	1,229
Dispositions	(41,034)	(13,075)	(54,108)	–	–	–	(8,288)	(2,658)	(10,946)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	33,087	14,905	47,993	164,065	38,835	202,900	45,098	15,711	60,809
Economic Factors	(8,187)	(20,847)	(29,034)	–	–	–	(1,162)	(4,040)	(5,203)
Technical Revisions	16,671	(31,265)	(14,594)	57,767	47,092	104,859	25,158	(5,277)	19,882
Production	(59,144)	–	(59,144)	(68,681)	–	(68,681)	(37,199)	–	(37,199)
December 31, 2014	**331,709**	**124,721**	**456,430**	**564,583**	**275,357**	**839,940**	**284,525**	**144,766**	**429,291**

UNDEVELOPED RESERVES

The following tables disclose the volumes of proved undeveloped reserves and probable undeveloped reserves of the Corporation that were first attributed in the years indicated.

Proved Undeveloped Reserves

	Crude Oil					
Year[(1)]	Light & Medium	Heavy	NGLs	Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
Aggregate Prior to 2012	35,414	7,734	2,461	280,727	41,564	99,324
2012	6,956	2,835	372	2,628	21,876	14,247
2013	2,335	1,526	36	14,905	67,821	17,685
2014	3,449	1,590	293	16,493	59,914	18,067

Probable Undeveloped Reserves

	Crude Oil					
Year[(1)]	Light & Medium	Heavy	NGLs	Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
Aggregate Prior to 2012	27,330	2,743	1,846	165,236	81,331	73,014
2012	15,332	504	1,054	26,082	55,224	30,441
2013	12,844	1,751	827	11,990	98,491	33,836
2014	2,224	1,568	183	8,183	22,367	9,067

Note:

(1) First attributed volumes include additions during the year and do not include revisions to previous undeveloped reserves.

The Corporation attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information and the optimization of existing fields. The Corporation has been very active for the last several years in drilling and developing these undeveloped reserves and, based on the estimates of future capital expenditures, the Corporation expects this to continue.

SIGNIFICANT FACTORS OR UNCERTAINTIES

Changes in future commodity prices relative to the forecasts described above under "– *Forecast Prices and Costs*" could have a negative impact on the Corporation's reserves, and in particular on the development of undeveloped reserves, unless future development costs are also reduced. Other than the foregoing and the factors disclosed or described in the tables above, the Corporation does not anticipate any other significant economic factors or other significant uncertainties which may affect any particular components of its reserves data.

For further information, see "*Risk Factors – The Corporation's actual reserves and resources will vary from its reserves and resources estimates, and those variations could be material*".

PROVED AND PROBABLE RESERVES NOT ON PRODUCTION

The Corporation has approximately 28.1 MMBOE of proved plus probable reserves which are capable of production but which, as of December 31, 2014, were not on production. These reserves have generally been non-producing for periods ranging from a few months to more than five years. The majority of these reserves are related to reserves volumes from recently drilled wells which require the completion of infrastructure before production can begin. A minor portion of these reserves are related to commercially producible volumes that are not producing due to production requirements of other reserve formations or zones in the same well bore.

Supplemental Operational Information

SAFETY AND SOCIAL RESPONSIBILITY

The Corporation has adopted a Health and Safety Policy, an Environment Policy and a Stakeholder Engagement Policy (collectively, the "**S&SR Policies**") that articulate its commitment to safety and social responsibility ("**S&SR**"). The S&SR Policies apply to any activities undertaken by or on behalf of the Corporation in its operating areas. The Safety & Social Responsibility Committee and the Corporation's management are responsible for approving, revising and implementing the S&SR Policies, overseeing the Corporation's S&SR performance, and ensuring there are adequate systems in place to support ongoing compliance and to plan and execute the Corporation's activities in a safe and socially responsible manner. Oversight and coordination of the S&SR Policies reside with the Corporation's S&SR department.

The Corporation strives to develop and operate its oil and natural gas assets in a socially responsible manner and places a high priority on preserving the quality of the environment, protecting the health and safety of its employees, contractors and the public in the communities in which it operates, encouraging active and open collaboration with its stakeholders. The Corporation has established processes and programs designed to evaluate and minimize health and safety and environmental risks. The Corporation actively participates in industry recognized programs that support its sustainability goals, and expects continuous improvement.

The Health and Safety Policy articulates the Corporation's commitment to protecting the health and safety of all persons and communities involved in, or affected by, its business activities. The Health and Safety Policy outlines specific commitments, including: (i) striving to ensure no harm to employees, contractors or the public; (ii) complying with relevant acts, codes, laws, regulations, standards and procedures; (iii) providing resources, training and technology to meet health and safety objectives; (iv) consulting with stakeholders on issues related to health and safety; and (v) auditing and inspecting operations as part of continuously improving safe work practices.

The Environment Policy articulates the Corporation's commitment to conducting its activities within the environmental regulations that govern the oil and gas industry within each of its operating jurisdictions and also to proactively mitigate impacts on the environment. The Environment Policy states the Corporation will: (i) consider actions taken in the context of their economic, environmental and social effects; (ii) safeguard the environment with actions, including spill prevention and the mitigation of gas flaring and venting, and be prepared to provide a timely and effective response to unexpected releases of environmental contaminants; (iii) work to reduce waste and improve the efficiency of fresh water use; and (iv) work to improve energy efficiency.

The Stakeholder Engagement Policy articulates the Corporation's commitment to engaging with its stakeholders in a way that fosters mutually beneficial relationships to promote positive economic and social development in its operating areas. The Stakeholder Engagement Policy states the Corporation will: (i) actively and openly collaborate with its stakeholders; (ii) ensure its stakeholders have access to timely, accurate information regarding current or planned operations and projects; (iii) strive to provide local suppliers of goods and services that meet the Corporation's procurement standards with opportunities to participate in its operations and projects; and (iv) develop long-lasting relationships based on trust, mutual respect and common understanding where the Corporation's activities will have a long-lasting impact on the communities in which it operates.

Health and Safety

The Corporation's employee recordable injury frequency rate decreased from 0.54 injuries per 200,000 man hours in 2013 to 0.40 injuries per 200,000 man hours in 2014. The Corporation's contractor total recordable injury frequency increased from 1.23 injuries per 200,000 man hours in 2013 to 2.17 injuries per 200,000 man hours in 2014. The Corporation's 2014 combined employee/contractor recordable injury frequency rate was 1.43 injuries per 200,000 man hours, an increase from 2013.

Health and safety risks influence workplace practices, operating costs and the establishment of regulatory standards. The Corporation maintains a health and safety management system designed to:

- increase emphasis on safety awareness and to promote continuous improvement and safety excellence;
- provide staff with the training and resources needed to complete work safely;
- support and participate in the Canadian Association of Petroleum Producers ("**CAPP**") Responsible Canadian Energy Program to improve safety performance;

- incorporate hazard assessment and risk management as an integral part of everyday business; and
- monitor performance to ensure that its operations comply with all legal obligations and its internally-imposed standards.

The health and safety component of the S&SR system is reviewed annually for continuous improvement opportunity. Every three years, the Health and Safety Management System is subject to a third-party audit utilizing the Enform Certificate of Recognition ("**COR**") Audit Protocol. Annual maintenance audits against the COR Audit Protocol are conducted each year. In 2014, the Corporation successfully renewed its COR certification.

The Corporation continues to develop and implement prevention measures and safety management program improvements to support its focus and commitment for an injury-free workplace.

Environment

The Corporation is committed to meeting its responsibilities to protect the environment through a variety of programs and actively monitors its operations for compliance with all regulations. In particular, the Corporation engages in the following activities:

- The Corporation supports and participates in the CAPP Responsible Canadian Energy program. The Corporation's participation in this program since its inception demonstrates its commitment to responsible resource development and to continuous improvement in environment, health and safety and social performance;
- Site abandonment, remediation and reclamation capital expenditures for the Corporation's Canadian properties in 2014 totaled $19.4 million ($13.5 million on operated properties and $5.9 million on non-operated properties). The Corporation's U.S. abandonment capital expenditures totaled $0.7 million (operated and non-operated). The Corporation received 4 reclamation certificates in 2014 by returning sites to that of equivalent land capability;
- The Corporation completes third-party environmental compliance inspections designed to ensure compliance with environmental legislation and regulations, and in 2014 six audits were completed and averaged a score of 80% to 90% compliance;
- The Corporation completes third-party audits to identify and evaluate the risk exposures associated with production equipment, process operations, utility supply systems and natural hazards. In 2014, eight facilities were audited. The purpose of these audits is to generate detailed loss prevention reports with risk-based recommendations for improving the overall safety and performance of our facilities, mitigating the potential exposure to financial loss associated with property damage and production loss, and ensuring the adequacy of our relevant insurance coverage;
- The Corporation's regulatory team completed nine internal environmental and regulatory audits at selected facilities. The average score of compliance resulting from the internal audit program in 2014 was 81%;
- The Corporation continued its internal facility inspections program and completed 64 inspections at major Canadian facilities in 2014. The average score of compliance resulting from the internal inspection program in 2014 was 90%. In addition, there were 28 well site inspections completed in Canada;
- In the United States, the Corporation continued its internal environmental and regulatory inspections. Frequent inspections were conducted at the Corporation's West Virginia, Pennsylvania, Montana and North Dakota sites along with routine drilling rig inspections;
- The Corporation conducts annual property reviews in Canada with specific risk reduction objectives. The Corporation also continues to manage risk through the implementation of a Pipeline Risk Assessment Program and various other activities, such as inspections of pipelines at water crossings. The Corporation reviews each pipeline system annually. The Corporation continues to incorporate improvements to these programs which are designed to identify and mitigate significant risks, and to decrease the number and severity of pipeline failure incidents;
- The Corporation has estimated its direct emissions in 2014 to be approximately 620,541 carbon dioxide equivalent tonnes per year, which is slightly more than the Corporation's direct emissions in 2013 of 616,537 carbon dioxide equivalent tonnes per year. The estimated numbers will be adjusted as additional data becomes available. In 2014, the Corporation completed 18 fugitive emissions infrared surveys at its Canadian facilities to detect losses from leaks and vents and is working to repair identified leaks.

Greenhouse gas regulations have been enacted in British Columbia, Alberta and at the federal level in Canada and the U.S. In British Columbia, the Corporation is subject to the carbon tax introduced in mid-2008. The total carbon tax paid was approximately $0.8 million in 2014. In addition, the Corporation is required to report third party verified greenhouse gas emissions annually to the government of British Columbia under the Greenhouse Gas Reduction (*Cap and Trade) Act* (British Columbia) (the "**BCCTA**"). The Corporation is not subject to the Canadian greenhouse gas emissions reporting requirement as it does not currently operate facilities above the 50,000 tonnes of carbon dioxide equivalent per year threshold. However, the Corporation is subject to the reporting requirement in the U.S. under the *Clean Air Act* and the Mandatory Reporting of Greenhouse Gases Rule. The latest of these reports was submitted to the U.S. Environmental Protection Agency on March 31, 2014 for the 2013 operational year. The report for the 2014 operational year will be submitted on March 31, 2015. For more information on the environmental regulation applicable to the Corporation, see "*Industry Conditions – Environmental Regulation*".

The Corporation endeavours to carry out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice. In particular, with respect to hydraulic fracturing, the Corporation complies with all current Canadian and U.S. regulations and adheres to all CAPP Hydraulic Fracturing Operating Practices. The Corporation proactively employs alternative fracturing technology such as foams, gelled water and reclaimed water to reduce the amount of fresh water required during the fracturing process. The Corporation actively seeks opportunities to collaborate with other area operators to share flowback fluid where feasible through inter-company transfers. Although the Corporation proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the United States impose more stringent compliance requirements surrounding hydraulic fracturing.

Health, safety, environmental and regulatory updates and risks are reviewed regularly by the Safety & Social Responsibility Committee of the Corporation's board of directors. At present, the Corporation believes that it is, and expects to continue to be, in compliance with all material applicable environmental laws and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet its ongoing environmental obligations.

Overall, the Corporation strives to operate in a socially responsible manner and believes its health, safety and environmental initiatives confirm its ongoing commitment to environmental stewardship and the health and safety of its employees, contractors and the general public in the communities in which it operates. Annually, the Corporation identifies key focus areas to support this commitment and sets forth strategic reduction targets. The Corporation believes that by monitoring metrics, identifying areas for improvement and implementing strategies, processes and procedures in those key focus areas, the Corporation can reduce its environmental impact.

INSURANCE

The Corporation carries insurance coverage to protect its assets at or above the standards typical within the oil and natural gas industry. Insurance levels are determined and acquired by the Corporation after considering the perceived risk of loss and appropriate coverage, together with the overall cost. The Corporation currently purchases insurance to protect against third party liability, property damage, business interruption, pollution and well control. In addition, liability coverage is also carried for the directors and officers of the Corporation.

PERSONNEL

As at December 31, 2014, the Corporation employed a total of 726 persons, including full-time benefit and payroll consultants, 577 of whom were in Canada and 149 of whom were in the United States.

Description of Capital Structure

The authorized capital of the Corporation consists of an unlimited number of Common Shares and a number of preferred shares, issuable in series ("**Preferred Shares**"), which are limited to an amount equal to not more than one-quarter of the number of issued and outstanding Common Shares at the time of the issuance of any such Preferred Shares. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares. Copies of the Corporation's articles of amalgamation and bylaws were filed on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov on January 2, 2013 and June 16, 2014, respectively.

COMMON SHARES

Holders of Common Shares are entitled to receive notice of and to attend all meetings of shareholders of the Corporation and to one vote at such meetings for each Common Share held. The holders of the Common Shares are, at the discretion of the Corporation's board of directors and subject to applicable legal restrictions and subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Corporation, entitled to receive any dividends declared by the Corporation on the Common Shares and to share in the remaining property of the Corporation upon liquidation, dissolution or winding-up.

The articles of the Corporation, as amended and restated on May 11, 2012, contain provisions facilitating payment of dividends on Common Shares through issuance of Common Shares in circumstances where the Board of Directors discloses, and a shareholder of the Corporation validly elects to receive, payment of dividends, in whole or in part, in the form of Common Shares. See "*Dividends – Stock Dividend Program*".

PREFERRED SHARES

There are no Preferred Shares outstanding as of the date of this Annual Information Form. The Preferred Shares may be issued from time to time in one or more series with such rights, restrictions, privileges, conditions and designations attached thereto as shall be fixed from time to time by the Corporation's board of directors. Subject to the provisions of the ABCA, the Preferred Shares of each series shall rank in parity with the Preferred Shares of every other series. The Preferred Shares shall be entitled to preference over the Common Shares and any other shares of the Corporation ranking junior to the said Preferred Shares with respect to payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, to the extent fixed in the case of each respective series, and may also be given such other preferences over the Common Shares and any other shares of the Corporation ranking junior to the said Preferred Shares as may be fixed in the case of each such series.

SHAREHOLDER RIGHTS PLAN

The continuation and amendment and restatement of the Shareholder Rights Plan was approved by shareholders of the Corporation, including by requisite number of the Corporation's "Independent Shareholders" (as defined in the Shareholder Rights Plan), at the annual meeting held on May 10, 2013. The continuation of the Shareholder Rights Plan must next be approved by the Corporation's "Independent Shareholders" at the annual meeting of shareholders of the Corporation to be held in 2016, failing which it will expire at the end of such meeting. The Shareholder Rights Plan, under which Computershare Trust Company of Canada acts as rights agent, generally provides that, following the acquisition by any person or entity of 20% or more of the issued and outstanding Common Shares (except pursuant to certain permitted or excepted transactions) and upon the occurrence of certain other events, each holder of Common Shares, other than such acquiring person or entity, shall be entitled to acquire Common Shares at a discounted price. The Shareholder Rights Plan is similar to other shareholder rights plans adopted in the energy sector. A copy of the Shareholder Rights Plan was filed on May 10, 2013 as a "Security holders documents" on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov, and is available on the Corporation's website at www.enerplus.com under "Corporate Governance".

SENIOR UNSECURED NOTES

Enerplus has issued Senior Unsecured Notes, of which US$850.8 million and CDN$70 million principal amounts were outstanding at December 31, 2014. Certain terms of the Senior Unsecured Notes are summarized below:

Issue Date	Original Principal	Remaining Principal	Coupon Rate	Interest Payment Dates	Maturity Date	Term
September 3, 2014	US$200 million	US$200 million	3.79%	March 3 and September 3	September 3, 2026	Principal payment required in five equal annual installments beginning September 3, 2022
May 15, 2012	CDN$30 million	CDN$30 million	4.34%	May 15 and November 15	May 15, 2019	Bullet payment on maturity
May 15, 2012	US$20 million	US$20 million	4.40%	May 15 and November 15	May 15, 2022	Bullet payment on maturity
May 15, 2012	US$355 million	US$355 million	4.40%	May 15 and November 15	May 15, 2024	Principal payment required in five equal annual installments beginning May 15, 2020
June 18, 2009	CDN$40 million	CDN$40 million	6.37%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$40 million	US$40 million	6.82%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$225 million	US$225 million	7.97%	June 18 and December 18	June 18, 2021	Principal payments required in five equal annual installments beginning June 18, 2017
October 1, 2003	US$54 million	US$10.8 million	5.46%	April 1 and October 1	October 1, 2015	One (out of five) remaining principal payment of equal annual installments required on October 1, 2015

For additional information see "*Material Contracts and Documents Affecting the Rights of Securityholders*".

BANK CREDIT FACILITY

As of December 31, 2014, the Corporation had $79.9 million drawn on a $1.0 billion senior unsecured, covenant-based credit facility with a syndicate of financial institutions maturing October 31, 2017. For a description of the Bank Credit Facility, see Note 8 to the Corporation's audited consolidated financial statements for the year ended December 31, 2014. See also "*Material Contracts and Documents Affecting Rights of Securityholders*".

Dividends

DIVIDEND POLICY AND HISTORY

The Corporation's board of directors is responsible for determining the dividend policy of the Corporation. The dividend policy must comply with the requirements of the ABCA, including satisfying the solvency test applicable to ABCA corporations. The Corporation has currently established a dividend policy of paying monthly dividends to holders of Common Shares. The dividend record date is on or about the last business day of each calendar month and the corresponding dividend payment date is on or about the 15th day of the following month. **However, any decision to pay dividends on the Common Shares will be made by the Corporation's board of directors on the basis of the relevant conditions existing at such future time, and there can be no guarantee that the Corporation will maintain its current dividend policy. Dividend amounts will likely vary, and there can be no assurance as to the level of dividends that will be paid or that any dividends will be paid at all.** See "*Risk Factors – Dividends on the Corporation's Common Shares are variable*". Monthly cash dividends paid to U.S. resident shareholders are converted to U.S. dollars based upon the actual Canadian to U.S. dollar exchange rate on the dividend payment date and, accordingly, shareholders that are not resident in Canada are subject to foreign exchange rate risk on such payments.

The table below sets forth the dividends paid or declared by the Corporation in 2012, 2013, 2014 and January through April of 2015:

Month	2015	2014	2013	2012
January	$ 0.09	$ 0.09	$ 0.09	$ 0.18
February	0.09	0.09	0.09	0.18
March	0.09	0.09	0.09	0.18
April	0.05	0.09	0.09	0.18
May	N/A	0.09	0.09	0.18
June	N/A	0.09	0.09	0.18
July	N/A	0.09	0.09	0.09
August	N/A	0.09	0.09	0.09
September	N/A	0.09	0.09	0.09
October	N/A	0.09	0.09	0.09
November	N/A	0.09	0.09	0.09
December	N/A	0.09	0.09	0.09

For certain tax information relating to the dividends paid on the Common Shares for Canadian and U.S. federal income tax purposes, please refer to the Corporation's website at www.enerplus.com.

Shareholders are advised to consult their tax advisors regarding questions relating to the tax treatment of dividends paid by the Corporation. For additional information on potential risks associated with the taxation of dividends paid by the Corporation, see "*Risk Factors*".

STOCK DIVIDEND PROGRAM

Effective May 11, 2012, the Corporation implemented a stock dividend program pursuant to which shareholders of the Corporation were able to elect to receive dividends in the form of Common Shares, instead of receiving a cash dividend, issued at a deemed price of 95% of the five day weighted average trading price of the Common Shares on the TSX immediately prior to the applicable dividend payment date. Effective with the April 2014 dividend, the Corporation elected to eliminate the 5% discount applied to determine the number of shares issued pursuant to the stock dividend program. Effective September 19, 2014, the board of directors of the Corporation suspended the stock dividend program to eliminate the dilution associated with the issuance of shares through the program.

Industry Conditions

OVERVIEW

The oil and natural gas industry is subject to extensive controls and regulation governing its operations (including land tenure, exploration, development, production, refining, transportation, marketing, remediation, abandonment and reclamation) imposed by legislation enacted by various levels of government. The oil and natural gas industry is also subject to agreements among the various federal, provincial and state governments with respect to pricing and taxation of oil and natural gas. Although it is not expected that any of these controls, regulations or agreements will affect the Corporation's operations in a manner materially different than they would affect other oil and gas issuers in similar operating areas, the controls, regulations and agreements should be considered carefully by investors in the oil and 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.

The Corporation owns oil and natural gas properties and related assets in Canada (primarily in Alberta, Saskatchewan and British Columbia) and in Montana, North Dakota, Pennsylvania and West Virginia in the United States. The Corporation's U.S. oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. The Corporation's U.S. operations are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit or limit the venting or flaring of natural gas and associated liquids, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

PRICING AND MARKETING OF CRUDE OIL AND NATURAL GAS

In Canada and the Unites States, producers of crude oil negotiate sales contracts directly with crude oil purchasers. Most agreements are linked to global oil prices, which are set by daily, weekly and monthly physical and financial transactions for crude oil around the world. Those prices are primarily based on worldwide fundamentals of supply and demand. Specific prices depend, in part, on crude oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance and other contractual terms.

In Canada and the United States, producers of natural gas are free to negotiate prices and other terms with purchasers, provided that the export contract meets certain criteria prescribed by the National Energy Board and the Government of Canada or, in relation to U.S. exports, restrictions on export licenses imposed by the United States Department of Energy. The price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, seasonal factors, weather conditions, the value of refined products, the supply/demand balance and other contractual terms. In the United States, the Federal Energy Regulatory Commission regulates interstate natural gas rates and service conditions, which affect the marketing of natural gas, as well as revenues producers receive for sales of natural gas. Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies.

Internationally, prices for crude oil and natural gas fluctuate in response to changes in the supply and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond the Corporation's control. Since mid-2014, crude oil and natural gas prices experienced significant decline and have fluctuated in response to a variety of factors including, among others, the increase in supply of crude oil and the refusal by the Organization of the Petroleum Exporting Countries to decrease production levels in response to such increase. See "*Risk Factors – Low or volatile oil and natural gas prices could have a material adverse effect on the Corporation's results of operations and financial condition*". In addition, crude oil and natural gas producers in North America currently receive significantly discounted prices for their production relative to certain international prices as a result of constraints on the ability to transport and sell their products to international markets due to lack of infrastructure capacity. See "*Risk Factors – Lack of adequately developed infrastructure may result in a decline in the Corporation's ability to market oil and natural gas production*".

ROYALTIES AND INCENTIVES

In addition to federal regulations, each province in Canada and each U.S. state has legislation and regulations which govern oil and gas holdings and land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions, producers of oil and natural gas are required to pay annual rental payments and royalties in respect of Crown leases, and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. In all U.S. jurisdictions, producers of oil and natural gas are typically required to pay annual rental payments in respect of federal, state and freehold leases until production begins. Upon commencement of production, royalties and production taxes are paid in respect of oil and natural gas produced from federal, state and freehold lands. Producers of U.S. Indian leases are required to pay annual rental payments regardless of well production, in addition to other fixed fees for land improvement, on a per well basis. Royalty and production tax regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown-owned lands in Canada and federal and state lands in the U.S. are determined by negotiations between the freehold mineral owner and the lessee. Crown royalties in Canada and federal, U.S. Indian and state royalties and production taxes in the U.S. are determined by government regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date 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 or net profits or net carried interests.

From time to time, the federal and provincial governments in Canada and the federal and state governments in the U.S. have established incentive programs which have included royalty rate or production tax reductions (including for specific wells), royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. If applicable, oil and natural gas royalty holidays, reductions and tax credits would effectively reduce the amount of royalties paid by oil and gas producers to the applicable governmental entities.

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 oil and natural gas pursuant to leases, licences and permits for varying periods 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 oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Crude oil and natural gas located in the U.S. is predominantly owned by private owners. The Federal Government Bureau of Land Management ("**BLM**"), and the state in which the minerals are located also may hold ownership to such rights. These owners, from governmental bodies to private individuals, grant rights to explore for and produce oil and gas pursuant to leases, licenses and permits for varying periods and on conditions including requirements to perform specific work or make payments. As to those rights held by private owners, all terms and conditions may be negotiated. For those rights held by governmental agencies, typically the terms and conditions of the oil and gas lease have been predetermined by each governing or regulatory body. Substantially all of the leaseholds currently owned by the Corporation in the U.S. have been granted through private individuals.

The majority of the Corporation's operations in North Dakota take place on the Fort Berthold Indian Reservation ("**FBIR**") and involve allotee lands, which are lands that are administered by the Bureau of Indian Affairs ("**BIA**") but owned by individual band members. As such, these operations are governed by both state and federal regulations. The federal regulations are enforced by U.S. federal departments such as the BIA, the BLM, and the U.S. federal Environmental Protection Agency (the "**U.S. EPA**"). Federal U.S. regulations may differ significantly from regulations generally applicable to non-federally regulated lands and, as a consequence, have the effect of slowing or halting the Corporation's developments on the FBIR.

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

ENVIRONMENTAL REGULATION

The Corporation is subject to the applicable municipal, provincial, state and federal environment, health and safety laws and regulations in its operating areas in both Canada and the United States. These requirements provide for environmental protection and apply restrictions and prohibitions regarding disturbances and releases or emissions of various substances produced or utilized in association with oil and gas industry operations. Environmental laws may impose remediation obligations with respect to a property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused release of the substance and any past or present owner, tenant or other person in possession of the site. In addition, legislation and regulation requires that well, pipeline and facility sites are abandoned and reclaimed to the satisfaction of the applicable authorities. Compliance with these requirements can involve significant expenditures. A breach of such requirements may result in the imposition of material fines and penalties, the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage or the issuance of clean-up orders. See "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities*".

In British Columbia, energy projects may be subject to review pursuant to the provisions of the *Environmental Assessment Act* (British Columbia), which rolls the previous processes for the review of major energy projects into a single environmental assessment process that contemplates public participation in the environmental review. Other environmental protection and management measures, including reclamation, are governed by the *Oil and Gas Activities Act* (British Columbia) and the *Environmental Management Act* (British Columbia). In Alberta, the provincial government has instituted the *Responsible Energy Development Act* wherein a new, single regulatory body for upstream oil and gas was established. This single regulator, the AER, was created by a merger of the former Energy Resources Conservation Board and the Alberta Environment and Sustainable Resource Development. The intention of this merger is to provide a comprehensive streamlined regulatory process. The AER oversees compliance with the *Public Lands Act* and the *Mines and Mineral Act,* the *Water Act* and the *Environmental Protection and Enhancement Act* by oil and gas operators and imposes penalties for violations, which may be significant. In Saskatchewan, environmental regulation is governed by *The Environmental Management and Protection Act, 2002* (Saskatchewan), *The Environmental Assessment Act* (Saskatchewan) and *The Oil and Gas Conservation Act* (Saskatchewan).

In 2008, the Province of British Columbia instituted a carbon tax that applies to all fuel users and producers in the province, as well as the BCCTA, which requires third party verified greenhouse gas emissions to be reported annually. See "*Supplemental Operational Information – Safety and Social Responsibility – Environment*". The Province of British Columbia is in discussions with stakeholders and partners of the Western Climate Initiative to develop an Emissions Trading Regulation and an Offsets Regulation under the BCCTA to price carbon and to reduce greenhouse gas emissions of regulated emitters through a regional cap and trade program. The Corporation is unable to estimate the future potential compliance costs of these pending regulations without a carbon price or an allocation of emission allowances. However, given the Corporation's current hydrocarbon production levels in British Columbia and a current price of carbon offsets in the marketplace of approximately $15 per tonne of carbon dioxide equivalent, the Corporation does not expect such costs to be material.

The Province of Alberta has instituted emission reduction targets for large emitters (e.g., 100,000 tonnes of carbon dioxide per year at a single facility), which could result in increased capital expenditures and operating costs. Currently, the Corporation does not operate any facility classed within this large emitter category. In 2010, the Alberta provincial government and the Canadian federal government aligned in support of regulations that require the reporting of greenhouse gas emissions at facilities that meet or exceed a 50,000 tonne per year carbon dioxide equivalent emissions threshold. Currently, the Corporation does not operate any facility classed within this category. Additionally, the Province of Saskatchewan has passed, but not yet proclaimed, the *Management and Reduction of Greenhouse Gases Act* (Saskatchewan), which would require regulated emitters to report and reduce their greenhouse gas emissions below a prescribed amount below their individual baseline emission level. The Corporation does not operate any facility classed within the regulated emitter category in Saskatchewan based on the 50,000 tonne per year carbon dioxide equivalent emissions threshold.

In the United States, oil and gas operations are regulated at the federal, state, county and tribal levels of government. At the federal level, well planning and permitting is primarily regulated by the U.S. Department of Interior's BLM and BIA for operations on public and tribal lands under the *Federal Land Policy and Management Act* and the *National Environmental Policy Act*. Environmental conservation and cultural and natural resources protection at the federal level are administered by numerous agencies under multiple statutes.

Planning, permitting and compliance related to environmental media protection and contaminants at the federal level are administered by the U.S. EPA, or by various states whose programs have been granted primacy by the U.S. EPA. The U.S. EPA governs federal legislation, including the *Clean Air Act*, the *Clean Water Act*, the *Resource Conservation and Recovery Act* (other than oil and gas exempt wastes), the *Comprehensive Environmental Response, Compensation and Liability Act*, the *Oil Pollution Act*, the *Emergency Planning and Community Right-to-Know Act* and the *Safe Drinking Water Act* and Federal Executive Orders.

The Corporation's U.S. operations are subject to various regulations, including those relating to well permits, linear facilities, hydraulic fracturing, underground injection and setbacks (buffers) for environmental protection, imposed by a number of state agencies regulating oil and gas activities. In addition to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, water quality, fish, wildlife, visual quality, transportation, noise, spills and incidents and transportation.

The U.S. EPA announced on December 7, 2009 its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment. These findings by the U.S. EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal *Clean Air Act*. One such regulation that has been issued is the Mandatory Reporting of Greenhouse Gases Rule in which petroleum and natural gas systems above a certain threshold at an onshore basin level are required to submit an annual greenhouse gas emissions report. The Corporation is subject to this regulation and reporting requirement.

Additional regulations affecting the Corporation's U.S. operations include the following: the Federal Implementation Plan for Oil and Natural Gas Well Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), North Dakota; and the Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. These regulations provide emission control requirements for the Corporation's U.S. assets, as well as increased monitoring, recordkeeping, reporting, and regulatory oversight.

At the request of Congress, in 2011 the U.S. EPA began research under its *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. The purpose of the study is to assess the potential impacts of hydraulic fracturing on drinking water resources, and to identify the driving factors that may affect the severity and frequency of such impacts. The focus is primarily on hydraulic fracturing of shale formations to extract natural gas, with some study of other oil-and gas-producing formations, including tight sands, and coalbeds. The BLM, which regulates oil and gas operations located on federal and tribal lands, published its latest proposed hydraulic fracturing rules on May 16, 2013. All of the Corporation's operations on the FBIR are regulated by the BLM. Congress has also initiated various countermeasures aimed at restricting federal agencies' authority to impose new hydraulic fracturing regulations. The political response from Congress is largely in reaction to the BLM's proposed rules, the lingering U.S. EPA study and several other federal agency efforts to study the issue. The intent of these countermeasures is to limit federal over-reach on an issue that is considered best managed at the state level.

All U.S. states in which the Corporation operates have regulations on hydraulic fracturing disclosure. Additionally, Pennsylvania and West Virginia have rules applicable to the tracking of water usage and management of flowback water. Enerplus utilizes the internet-based chemical registry FracFocus for posting of the required disclosure information. FracFocus is operated by the Ground Water Protection Council, a group of state water officials, and the Interstate Oil and Gas Compact Commission, an association of oil and gas producing states. The online registry was created in 2011, in response, at least in part, to concerns from landowners about the chemical content of fracturing fluids that were being injected into oil and gas wells on their land as well as adjacent properties. FracFocus is widely accepted among the petroleum industry, and the Corporation utilizes the registry in all four states in which it operates. Currently, FracFocus lists over 700 companies as registry participants.

Implementation of more stringent environmental regulations on the Corporation's U.S. operations could affect the capital and operating expenditures and plans for the Corporation's U.S. operations. The Corporation minimizes the potential of these impacts to U.S. operations in many ways, including through participation and membership in trade organizations such as North Dakota Petroleum Council, Montana Petroleum Association, West Virginia Oil and Natural Gas Association, Independent Petroleum Association of America and Western Energy Alliance. In addition, the Corporation participates directly in legislative hearings, rulemaking processes, meetings with state officials and local stakeholder groups, and provides both written and verbal comment on proposed legislation and regulations. As in Canada, the Corporation's U.S. operations endeavour to carry out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice.

In July of 2014, the North Dakota Industrial Commission ("**NDIC**") finalized a new rule that imposes restrictions on the flaring of gas. The rule establishes gas capture rates that must be met by operators to avoid the imposition of crude oil production curtailments. These gas capture rates went into effect in October 2014. The need for an operator to flare gas primarily stems from the fact that the rate of oil and gas development in North Dakota currently outpaces the construction of gas gathering and processing infrastructure. This situation is the result of various factors, including delays in obtaining right of way approvals, which is particularly cumbersome with respect to operations taking place on FBIR due to the application of additional regulatory requirements. The Corporation is working diligently with its midstream partner and the regulators to expand gas gathering capacity and increase gas capture rates. One measure being taken is the installation of NGL processing skids which are being used to extract NGLs from gas that would have otherwise been flared. See "*Risk Factors – The Corporation may be subject to curtailments in production due to environmental regulations, volatility in commodity prices and third party operational business practices*".

In December of 2014, NDIC adopted new conditioning standards aimed at improving the safety of crude oil when transported. The regulation focuses on ensuring that produced crude oil is sufficiently conditioned at the well site to remove volatility characteristics that might pose unreasonable transportation hazards, regardless of the mode of transportation utilized. Based on extensive analytical work performed over the last year, the Corporation does not anticipate any issues in meeting these requirements. Beginning with the second quarter of 2015, this rule will require quarterly monitoring of crude oil vapor pressure by the Corporation. The results of the analyses are to be submitted to the NDIC on a quarterly basis.

Subsequent to the International Climate Change meeting in Copenhagen in December 2009 the governments of the United States and Canada committed to a 17% reduction in greenhouse gas emissions by 2020 relative to a 2005 baseline. The Government of Canada is working towards this target on a sector by sector basis but has yet to finalize regulations pertaining to the oil and gas sector. A recent report from the National Roundtable on the Environment and Economy (2011) has recommended short-term actions for Canada to develop a national cap and trade program and to eventually link with a North American cap and trade system if the U.S. eventually develops and implements its own cap and trade system. However, as the Canadian federal government continues to seek to align its greenhouse gas regulations with those of the United States, it is unclear whether the Canadian federal government will pursue any short-term actions and therefore its regulations remain pending.

The Corporation believes that it is, and expects to continue to be, in material compliance with applicable environmental laws and regulations and is committed to meeting its responsibilities to protect the environment wherever it operates or holds working interests. The Corporation anticipates that this compliance may result in increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. See "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities"* and *"Risk Factors – Government regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs*".

WORKER SAFETY

The Corporation's oilfield operations must be carried out in accordance with safe work procedures, rules and policies contained in applicable safety legislation. Such legislation requires that every employer ensures the health and safety of all persons at any of its work sites and all workers engaged in the work of that employer. The legislation, which provides for incident reporting procedures, also requires that every employer ensure that all of its employees are aware of their duties and responsibilities under the applicable legislation. Penalties under applicable occupational health and safety legislation include significant fines and incarceration.

Risk Factors

The following risk factors, together with other information contained in this Annual Information Form, should be carefully considered before investing in the Corporation. Each of these risks may negatively affect the trading price of the Common Shares or the amount of dividends that may, from time to time and at the discretion of the Corporation's board of directors, be declared and paid by the Corporation to its shareholders. As stated above, references to "natural gas" refer to both natural gas and shale gas, unless otherwise specified.

Low or volatile oil and natural gas prices could have a material adverse effect on the Corporation's results of operations and financial condition.

The Corporation's results of operations and financial condition are dependent on the prices it receives for the oil and natural gas it produces and sells. Oil and natural gas prices have fluctuated widely during recent years and may continue to be volatile in the future. Oil and natural gas prices have decreased significantly since mid-2014 and have fluctuated in response to a variety of factors beyond the Corporation's control, including: (i) global energy supply, production and policies, including the ability of OPEC to set and maintain production levels in order to influence prices for oil; (ii) political conditions, including the risk of hostilities in the Middle East and global terrorism; (iii) global and domestic economic conditions, including currency fluctuations; (iv) the level of consumer demand, including demand for different qualities and types of crude oil and liquids; (v) the production and storage levels of North American natural gas and crude oil and the supply and price of imported oil and liquefied natural gas; (vi) weather conditions; (vii) the proximity of reserves and resources to, and capacity of, transportation facilities and the availability of refining and fractionation capacity; (viii) the ability, considering regulation and market demand, to export oil and liquefied natural gas and NGLs from North America; (ix) the effect of world-wide energy conservation and greenhouse gas reduction measures and the price and availability of alternative fuels; and (x) government regulations. Oil and natural gas producers in North America currently receive significantly discounted prices for some of their production due to regional constraints on the ability to transport and sell such production to international markets. Additionally, limited natural gas and NGLs processing capacity may result in producers not realizing the full price for liquids associated with their natural gas production. A failure to resolve such constraints may result in continued reduced commodity prices received by oil and natural gas producers such as the Corporation.

Any further decline in crude oil or natural gas prices may have a material adverse effect on the Corporation's operations, financial condition, borrowing ability, levels of reserves and resources and the level of expenditures for the development of the Corporation's oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting the Corporation's production volumes, or its desire to market its production in unsatisfactory market conditions. Furthermore, the Corporation may be subject to the decisions of third party operators who, independently and using different economic parameters than the Corporation, may decide to curtail production.

Dividends on the Corporation's Common Shares are variable.

Although the Corporation currently intends to pay monthly cash dividends to its shareholders, these cash dividends may be reduced or suspended. The amount of cash available to the Corporation to pay dividends can vary significantly from period to period for a number of reasons, including among other things: (i) the Corporation's operational and financial performance (including fluctuations in the quantity of the Corporation's oil, NGLs and natural gas production and the sales price that the Corporation realizes for such production (after hedging contract receipts and payments)); (ii) fluctuations in the costs to produce oil, NGLs and natural gas, including royalty burdens, and to administer and manage the Corporation and its subsidiaries; (iii) the amount of cash required or retained for debt service or repayment; (iv) amounts required to fund capital expenditures and working capital requirements; (v) access to equity markets; (vi) foreign currency exchange rates and interest rates; and (vii) the risk factors set forth in this Annual Information Form. The decision whether or not to pay dividends and the amount of any such dividend is subject to the discretion of the board of directors of the Corporation, which regularly evaluates the Corporation's dividend policy and the solvency test requirements of the ABCA. In addition, the level of dividends per Common Share will be affected by the number of outstanding Common Shares and other securities that may be entitled to receive cash dividends or other payments. Dividends may be increased, reduced or suspended entirely depending on the Corporation's operations and the performance of its assets. The market value of the Common Shares may deteriorate if the Corporation is unable to meet dividend expectations in the future, and that deterioration may be material.

To the extent that the Corporation uses internally-generated cash flow to finance acquisitions, development costs and other significant capital expenditures, the amount of cash available to pay dividends to the Corporation's shareholders may be reduced. To the extent that external sources of capital, including debt or the issuance of additional Common Shares or other securities of the Corporation, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain, develop or expand its oil and gas reserves and resources and to invest in assets, as the case may be, will be impaired. To the extent that the Corporation is required to use cash flow to finance capital expenditures, property acquisitions or asset acquisitions, as the case may be, the level of the Corporation's cash dividend payments to its shareholders may be reduced or even eliminated.

The board of directors of the Corporation has the discretion to determine the extent to which the Corporation's cash flow will be allocated to the payment of debt service charges as well as the repayment of outstanding debt. The payments of interest and principal with respect to the Corporation's third party indebtedness, including the Credit Facilities, rank ahead of dividend payments that may be made by the Corporation to its shareholders. An increase in the amount of funds used to pay debt service charges or reduce debt will reduce the amount of cash that may be available for the Corporation to pay dividends to its shareholders. In addition, variations in interest rates and scheduled principal repayments, if and as required under the terms of the Credit Facilities, could result in significant changes in the amount required to be applied to debt service. Certain covenants in agreements with lenders may also limit payments of dividends.

The Corporation's Credit Facilities and any replacement credit facility may not provide sufficient liquidity.

Although the Corporation believes that its existing Credit Facilities are sufficient, there can be no assurance that the current amount will continue to be available or will be adequate for the financial obligations of the Corporation or that additional funds can be obtained as required or on terms which are economically advantageous to the Corporation. The amounts available under the Credit Facilities may not be sufficient for future operations, or the Corporation may not be able to renew its Bank Credit Facility or obtain additional financing on attractive economic terms, if at all. The Bank Credit Facility is generally available on a three year term, extendable each year with a bullet payment required at the end of three years if the facility is not renewed. The Corporation renewed its Bank Credit Facility in 2014 and, accordingly, it currently expires on October 31, 2017. There can be no assurance that such a renewal will be available on favourable terms or that all of the current lenders under the facility will renew at their current commitment levels. If this occurs, the Corporation may need to obtain alternate financing. Any failure of a member of the lending syndicate to fund its obligations under the Bank Credit Facility or to renew its commitment in respect of such Bank Credit Facility, or failure of the Corporation to obtain replacement financing or financing on favourable terms, may have a material adverse effect on the Corporation's business, and dividends to shareholders may be materially reduced or eliminated, as repayment of such debt has priority over dividend payments by the Corporation to its shareholders.

In 2014, the Corporation made aggregate principal repayments on its Senior Unsecured Notes of US$45.8 million (CDN$64.7 million, including underlying derivatives) and will be required to repay CDN$40 million and US$50.8 million in principal amounts on its Senior Unsecured Notes in 2015. See "*Description of Capital Structure – Senior Unsecured Notes*" for repayment terms on existing Senior Notes. The repayment of the Senior Unsecured Notes may require the Corporation to obtain additional financing, which may not be available or may be available on unfavourable terms. The repayment of the Senior Secured Notes also has priority over dividend payments to the Corporation's shareholders.

The Corporation may require additional financing to maintain and expand its assets and operations.

In the normal course of making capital investments to maintain and expand the Corporation's oil, NGLs and natural gas reserves and resources, additional Common Shares or other securities of the Corporation may be issued, which may result in a decline in production per share and reserves and/or resources per share. Additionally, from time to time, the Corporation may issue Common Shares or other securities from treasury in order to reduce debt, complete acquisitions and maintain a more optimal capital structure. The Corporation may also dispose of existing properties or assets, including its equity holdings in other issuers, as a means of financing alternative projects or developments. To the extent that external sources of capital, including the availability of debt financing from banks or other creditors or the issuance of additional Common Shares or other securities, becomes limited, unavailable or available on less favourable terms, or if the Corporation is unable to dispose of its equity holdings as anticipated, the Corporation's ability to make the necessary capital investments to maintain or expand its oil, NGLs and natural gas reserves and resources will be impaired. To the extent that the Corporation is required to use additional cash flow to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of cash that may be available for the Corporation to pay dividends to its shareholders may be reduced.

The Corporation's risk management activities could expose it to losses.

The Corporation may use financial derivative instruments and other hedging mechanisms to limit a portion of the adverse effects resulting from volatility in natural gas and oil commodity prices. To the extent the Corporation hedges its commodity price and foreign exchange exposure, it may forego the benefits it would otherwise experience if commodity prices were to increase or if the Canadian dollar were to weaken relative to the US dollar. In addition, the Corporation's commodity and foreign exchange hedging activities could expose it to losses. These losses could occur under various circumstances, including if the other party to the Corporation's hedge does not perform its obligations under the hedge agreement. The Corporation has also entered into hedging arrangements to settle future payments under its equity-based long term incentive programs, which could result in the Corporation suffering losses to the extent the hedged costs of such arrangements exceed the actual costs that would otherwise be payable at the time of settlement.

Fluctuations in foreign currency exchange rates could adversely affect the Corporation's business.

The price that the Corporation receives for a majority of its oil and natural gas is based on U.S.-dollar denominated benchmarks and, therefore, the price that the Corporation receives in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the U.S. dollar may negatively impact the Corporation's net production revenue by decreasing the Canadian dollars the Corporation receives for a given sale in U.S. dollars while offering limited relief to the Corporation's cost structure, to the extent its costs are incurred in Canadian dollars. The Corporation conducts certain of its business and operations in the United States and is, therefore, exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. The Corporation also has U.S. dollar denominated Senior Notes and is exposed to foreign currency risk should the Canadian dollar weaken against the U.S. dollar. The Corporation may from time-to-time use derivative instruments to manage a portion of its foreign exchange risk, as described in Note 16(c) to the Corporation's audited consolidated financial statements for the year ended December 31, 2014.

The Corporation may be subject to curtailments in production due to environmental regulations, volatility in commodity prices and third party operational business practices.

Should the Corporation be required to curtail or shut-in production, damage to the reservoir may prevent the Corporation from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. This could result in a reduction to the Corporation's cash flow and production levels, and may result in the Corporation incurring additional operating and capital costs for the well to achieve prior production levels. Specifically, industry sales gas infrastructure capacity in northeastern Pennsylvania is inadequate relative to the amount of natural gas that can be produced, which results in oil and gas producers in this region, including the Corporation, being subject to significantly discounted prices and, therefore, potential production curtailments due to price.

An increase in operating costs or a decline in the Corporation's production level could have a material adverse effect on results of operations and financial condition.

Higher operating costs for the Corporation's properties will directly decrease the amount of the Corporation's cash flow. Electricity, chemicals, supplies, energy services and labour costs are a few of the Corporation's operating costs that are susceptible to material fluctuation. The level of production from the Corporation's existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond the Corporation's control. Higher operating costs or a significant decline in production could result in materially lower cash flow and, therefore, could adversely affect the trading price of the Common Shares and reduce the amount that may be available for dividend payments by the Corporation to shareholders.

The Corporation is subject to risk of default by the counterparties to the Corporation's contracts.

The Corporation is subject to the risk that the counterparties to its risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to the Corporation's joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to the Corporation may adversely affect the results of operations, cash flows and financial position of the Corporation.

Delays in payment for business operations could adversely affect the Corporation.

In addition to the usual delays in payment by purchasers of oil and natural gas to the Corporation or to the operators of the Corporation's properties (and the delays of those operators in remitting payment to the Corporation), payments between any of these parties may also be delayed by, among other things: (i) capital or liquidity constraints experienced by such parties, including restrictions imposed by lenders; (ii) accounting delays or adjustments for prior periods; (iii) delays in the sale or delivery of products or delays in the connection of wells to a gathering system; (iv) weather related delays, such as freeze-offs, flooding and premature thawing; (v) blow-outs or other accidents; or (vi) recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of the Corporation's cash flow and the payment of cash dividends to its shareholders in a given period and expose the Corporation to additional third party credit risks.

Lower oil and gas prices and higher costs increase the risk of write-downs of the Corporation's oil and gas property assets.

Under U.S. GAAP, the net capitalized cost of oil and gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer's fiscal year-end. The amount by which the net capitalized costs exceed the discounted value will be charged to net income. While these write-downs would not affect cash flow, the charge to earnings may be viewed unfavourably in the market. With the significant drop in commodity prices, there still remains a risk for a write-down under U.S. GAAP as the ceiling test under U.S. GAAP is based on trailing twelve month actual prices.

The Corporation's actual reserves and resources will vary from its reserves and resources estimates, and those variations could be material.

The value of the Common Shares depends upon, among other things, the reserves and resources attributable to the Corporation's properties. The actual reserves and resources contained in the Corporation's properties will vary from the estimates summarized in this Annual Information Form and those variations could be material. Estimates of reserves and resources are by necessity projections, and thus are inherently uncertain. The process of estimating reserves or resources requires interpretations and judgments on the part of petroleum engineers, resulting in imprecise determinations, particularly with respect to new discoveries. Different engineers may make different estimates of reserves or resources quantities and revenues attributable thereto based on the same data. Ultimately, actual reserves and resources attributable to the Corporation's properties will vary and be revised from current estimates, and those variations and revisions may be material. The reserves and resources information contained in this Annual Information Form is only an estimate. A number of factors are considered and a number of assumptions are made when estimating reserves and resources, such as, among other things: (i) historical production in the area compared with production rates from similar producing areas; (ii) future commodity prices, production and development costs, royalties and planned capital expenditures; (iii) initial production rates and production decline rates; (iv) ultimate recovery of reserves and resources and the success of future exploitation activities; (v) marketability of production; and (vi) the effects of government regulation and other government royalties or levies that may be imposed over the producing life of reserves and resources.

Reserves and resources estimates are based on the relevant factors, assumptions and prices on the date the evaluations were prepared. Many of these factors are subject to change and are beyond the Corporation's control. If these factors, assumptions and prices prove to be inaccurate, the Corporation's actual reserves and resources could vary materially from its estimates. Additionally, all such estimates are, to some degree, uncertain, and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable quantities of oil and natural gas, the classification of such reserves and resources based on risk of recovery and associated contingencies, and the estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric or probabilistic calculations and upon analogy to similar types of reserves or resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves or resources based upon production history may result in variations or revisions in the estimated reserves or resources, and any such variations or revisions could be material.

Reserves and resources estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil, natural gas and NGLs prices and operating costs. Market price fluctuations of commodity prices may render uneconomic the recovery of certain categories of petroleum or natural gas. Moreover, short-term factors may impair the economic viability of certain reserves or resources in any particular period.

Lack of adequately developed infrastructure may result in a decline in the Corporation's ability to market oil and natural gas production.

The Corporation's business depends in part upon the availability, proximity, and capacity of oil and natural gas gathering systems, pipelines and/or rail transportation systems and processing facilities to provide access to markets for its production. Canadian federal and provincial, as well as U.S. federal and state, regulation of oil and gas production as well as processing and transportation could adversely affect the Corporation's ability to produce and market oil and natural gas. In addition, the assets of the Corporation are concentrated in regions with varying levels of government regulations that could result in the imposition of a limit or ban on shipping of commodities by truck, pipeline or rail.

OIL AND NATURAL GAS GATHERING SYSTEMS

As new resource plays are developed, they generally experience a sharp increase in the amount of production being produced in the area which could exceed the existing capacity of the various gathering system infrastructure. The Corporation relies on the timely construction of adequate gathering systems that allow its crude oil and natural gas production to be transported from the wellhead to existing and/or new sales infrastructure systems, such as pipelines or rail terminals.

In North Dakota, the pace at which midstream companies are able to construct adequate gathering infrastructure to allow for the required capture of natural gas production associated with the development of crude oil resources may have an impact on the Corporation's ability to increase crude oil production in the region. Additionally, as exploration and drilling on the Corporation's Marcellus shale gas properties increases, the amount of natural gas being produced by the Corporation and others could exceed the capacity of the various gathering pipelines currently available in these areas. If these constraints remain unresolved, the Corporation's ability to transport its production to sales pipelines in these regions may be impaired and could adversely impact the Corporation's production volumes or realized prices from these areas.

In Western Canada, concerns over the integrity and safety of certain aging natural gas gathering and sales pipelines resulted in an order by Canadian regulators for a major pipeline company to reduce the maximum operating pressure of certain lateral connections onto sales pipelines in order to conduct safety inspections of these gathering pipelines within Alberta. This regulatory order may temporarily reduce the amount of firm natural gas transportation service available in certain areas of Western Canada until safety inspections are concluded and any safety risks are subsequently corrected over a number of years. This may result in reduced production volumes within the affected regions until the safety issues, if any, are properly mitigated by the pipeline operators.

SALES PIPELINES AND RAIL TRANSPORTATION SYSTEMS

Oil and natural gas producers in North America, and particularly in Canada and in the Marcellus region of the United States, currently receive significantly discounted prices for their production due to constraints on the ability to transport and sell such production to domestic and international markets. While the third party pipelines and railroad companies generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of sales pipeline and rail capacity. This is currently the case with natural gas sales pipelines in both Alberta and Pennsylvania, as well as on a number of proposed crude oil pipeline expansion projects in Western Canada. Unfavourable economic conditions or financing terms may defer or prevent the completion of certain pipeline projects, gathering systems or railway projects that are planned for such areas. Also, there may be operational reasons, including but not limited to maintenance activities, for curtailing transportation capacity. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. To the extent that the transportation capacity becomes insufficient in areas where the Corporation operates, the Corporation may have to defer the development of, or curtail production from, or shut-in its wells awaiting a pipeline connection, or other available transportation capacity, and/or sell its production at lower prices than it would otherwise realize, or than the Corporation currently projects. This would adversely affect the Corporation's results of, and cash flow from, operations.

The Corporation transports its crude oil production by a diverse mix of pipeline, rail (after title is transferred to buyer's name) and trucking transportation, all subject to various risks of cost escalation and new costs. In certain regions the Corporation is currently dependent upon only one means of transportation. With respect to rail transportation, there may be future incremental costs associated with transporting, and there is a risk that access to rail transport may be constrained, depending upon changes made to existing rail transport regulations. There is a potential for increased government regulations concerning the usage of certain types of tank cars that transport crude oil and NGLs by rail in Canada and the United States, and this could increase the cost of utilizing rail to transport crude oil and/or NGLs.

ACCESS TO PROCESSING FACILITIES

NGLs production requires processing at fractionation facilities in order to separate the liquids stream into individual saleable products. The Corporation and the industry as a whole relies on the addition of adequate fractionation capacity to ensure the timely and economic processing of its liquids and the continued production of its crude oil and natural gas associated with those liquids. Limited natural gas processing capacity in certain regions may result in producers not realizing the full price for NGLs associated with their natural gas production.

A failure to resolve any of the constraints described above may result in shut-in production or continued reduced commodity prices received by the Corporation and other oil and natural gas producers.

The Corporation's expanding portfolio of growth-oriented projects in recent years may expose it to increased operational and financial risks.

Projects including Marcellus shale gas and early stage natural gas prospects, including the Duvernay and Wilrich, are more exploration-oriented in nature than the Corporation has historically participated in. As a result, there is more risk that the Corporation's expenditures on land, seismic and drilling may not provide economic returns. To the extent the Corporation acquires properties or assets with a higher exploration risk profile, the risk associated with such acquisitions and the future development of those assets has greater uncertainty.

The Corporation may be unable to add or develop additional reserves or resources.

The Corporation adds to its oil and natural gas reserves primarily through acquisitions and ongoing development of its existing reserves and resources, together with certain exploration activities. As a result, the level of the Corporation's future oil and natural gas reserves is highly dependent on its success in developing and exploiting its reserves and resources base and acquiring additional reserves and/or resources through purchases or exploration. Exploitation, exploration and development risks arise for the Corporation and, as a result, may affect the value of the Common Shares and dividends to shareholders due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. Additionally, if capital from external sources is not available or is not available on commercially advantageous terms, the Corporation's ability to make the necessary capital investments to maintain, develop or expand its oil and natural gas reserves and resources will be impaired. Even if the necessary capital is available, the Corporation cannot assure that it will be successful in acquiring additional reserves or resources on terms that meet its investment objectives. Without these additions, the Corporation's reserves will deplete and, as a consequence, either its production or the average life of its reserves will decline.

The Corporation may not realize the anticipated benefits of its acquisitions or dispositions.

From time to time, the Corporation may acquire additional oil and natural gas properties and related assets. Achieving the anticipated benefits of such acquisitions will depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining and integrating the acquired assets and properties into the Corporation's existing business. These activities will require the dedication of substantial management effort, time and capital and other resources, which may divert management's focus, capital and other resources from other strategic opportunities and operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of future acquisitions. The risk factors set forth in this Annual Information Form relating to the oil and natural gas business and the operations, reserves and resources of the Corporation apply equally in respect of any future properties or assets that the Corporation may acquire. The Corporation generally conducts certain due diligence in connection with acquisitions, but there can be no assurance that the Corporation will identify all of the potential risks and liabilities related to the subject properties.

When acquiring assets, the Corporation is subject to inherent risks associated with predicting the future performance of those assets. The Corporation makes certain estimates and assumptions respecting the prospectivity and characteristics of the assets it acquires, which may not be realized over time. As such, assets acquired may not possess the value the Corporation attributed to them, which could adversely impact the Corporation's cash flows. To the extent that the Corporation makes acquisitions with higher growth potential, the higher risks often associated with such potential may result in increased chances that actual results may vary from the Corporation's initial estimates. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods, approaches and assumptions than those of the Corporation's engineers, and these initial assessments may differ significantly from the Corporation's subsequent assessments.

Furthermore, potential investors should be aware that certain acquisitions, and in particular acquisitions of higher risk/higher growth assets, and the development of those acquired assets may require capital expenditures from the Corporation, and the Corporation may not receive cash flow from operations from these acquisitions for several years or may receive cash flow in an amount less than anticipated. Accordingly, the timing and amount of capital expenditures may adversely affect the Corporation's cash flow.

The Corporation may also from time to time dispose of properties and assets. These dispositions may consist of non-core properties or assets or may consist of assets or properties that are being monetized in order to fund alternative projects or development by the Corporation. There can be no assurance that the Corporation will be successful in such dispositions or realize the amount of desired proceeds from such dispositions, or that such dispositions will be viewed positively by the financial markets, and such dispositions may negatively affect the Corporation's results of operations or the trading price of the Common Shares.

Since a portion of the Corporation's properties are not operated by the Corporation, results of operations may be adversely affected by the failure of third party operators.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of the Corporation's properties. In 2014, approximately 43% of the Corporation's production was from properties operated by third parties. This results in significant reliance on third party operators in both the operation and development of such properties and control over capital expenditures relating thereto. The timing and amount of capital required to be spent by the Corporation may differ from the Corporation's expectations and planning, and may impact the ability and/or cost of the Corporation to finance such expenditures, as well as adversely affect other parts of the Corporation's business and operations. To the extent a third party operator fails to perform its duties properly, faces capital or liquidity constraints or becomes insolvent, the Corporation's results of operations will be negatively impacted.

Further, the operating agreements governing the properties not operated by the Corporation typically require the operator to conduct operations in a good and "workmanlike" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except for liabilities that may result from the operator's gross negligence or wilful misconduct.

Government regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs.

The oil and gas industry operates under federal, provincial, state and municipal legislation and regulation governing such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, the imposition of specific drilling obligations, control over the development and abandonment of fields (including restrictions on production), and possibly expropriation or cancellation of contract rights. See "*Industry Conditions*". To the extent that the Corporation fails to comply with applicable government regulations or regulatory approvals, the Corporation may be subject to fines, enforcement proceedings (including "enforcement ladders" with varying penalties) and the restriction or complete revocation of rights to conduct its business, or to apply for regulatory approvals necessary to conduct its business, in the ordinary course.

Government regulations may be changed from time to time in response to economic or political conditions. Additionally, the Corporation's entry into new jurisdictions and its adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. For example, U.S. federal and state governments have increased their scrutiny of the usage and disposal of chemicals and water used in fracturing procedures in the oil and gas industry, while certain states, such as New York, have called for bans on oil and gas drilling using hydraulic fracturing. Similarly, Canadian regulatory bodies have enhanced their oversight of and reporting obligations associated with fracturing procedures. More activity by the Corporation on Indian lands in North Dakota also may increase compliance obligations under local or tribal rules. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could negatively impact the development of oil and gas properties and assets, reduce demand for crude oil and natural gas or impose increased costs on oil and gas companies, any of which could have a material adverse impact on the Corporation.

Additionally, various levels of Canadian and U.S. governments are considering or have implemented legislation to reduce emissions of greenhouse gases, including volatile organic compounds. See "*Industry Conditions – Environmental Regulation*" for a description of these initiatives. Because the Corporation's operations emit various types of greenhouse gases, such new legislation or regulation could increase the costs related to operating and maintaining the Corporation's facilities and could require it to install new emission controls on its facilities, acquire allowances for its greenhouse gas emissions, pay taxes, fees and other penalties related to its greenhouse gas emissions and administer and manage a greenhouse gas emissions program. The Corporation is not able at this time to estimate such increased costs; however, they could be significant. Any of the foregoing could have adverse effects on the Corporation's business, financial position, results of operations and prospects.

The Corporation may lose its current status as a "foreign private issuer" in the United States, which may result in additional compliance costs and restricted access to capital markets.

The Corporation is required to assess its "foreign private issuer" status under U.S. securities laws on an annual basis at the end of its second quarter. If the Corporation were to lose its status as a "foreign private issuer" under U.S. securities laws and is required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country, it may incur additional general and administrative compliance costs and may have restricted access to capital markets for a period of time until it has required approvals in place from the SEC.

The Corporation's operations are subject to certain risks and liabilities inherent in the oil and natural gas business, some of which may not be covered by insurance.

The Corporation's business and operations, including the drilling of oil and natural gas wells and the production and transportation of oil and natural gas, are subject to certain risks inherent in the oil and natural gas business. These risks and hazards include encountering unexpected formations or pressures, blow-outs, pipeline breaks, rail transportation incidents, craterings, fires, power interruptions and severe weather conditions. The Corporation's operations may also subject it to the risk of vandalism or terrorist threats, including eco-terrorism. The foregoing hazards could result in personal injury, loss of life, reduced production volumes or environmental and other damage to the Corporation's property and the property of others. The Corporation cannot fully protect against all of these risks, nor are all of these risks insurable. Although the Corporation carries liability, business interruption and property insurance in respect of such matters, there can be no assurance that insurance will be adequate to cover all losses resulting from such events or that the lost production will be restored in a timely manner. The Corporation may become liable for damages arising from these events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. While the Corporation has both safety and environmental policies in place to protect its operators and employees and to meet regulatory requirements in areas where they operate, any costs incurred to repair damage or pay liabilities would adversely affect the Corporation's financial position, including the amount of funds that may be available for dividend payments to shareholders.

In addition, the Corporation's unconventional oil and gas operations (such as the development and production of Bakken oil and shale gas) involve certain additional risks and uncertainties. The drilling and completion of wells and operations on these unconventional assets, particularly in the Marcellus shale region, present certain challenges that differ from conventional oil and gas operations. Wells on these properties generally must be drilled deeper than in many other areas, which makes the wells more expensive to drill and complete. The wells may also be more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore. In addition, the fracturing activities required to be undertaken on these unconventional assets may be more extensive and complicated than fracturing the geological formations in the Corporation's other areas of operation and require greater volumes of water than conventional wells. The management of water and the treatment of produced water from these wells may be more costly than the management of produced water from other geologic formations.

Unforeseen title defects, disputes or litigation may result in a loss of entitlement to production, reserves and resources.

From time to time, the Corporation conducts title reviews in accordance with industry practice prior to purchases of assets. However, if conducted, these reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat the Corporation's title to the purchased assets. If this type of defect were to occur, the Corporation's entitlement to the production and reserves (and, if applicable, resources) from the purchased assets could be jeopardized. Furthermore, from time to time, the Corporation may have disputes with industry partners as to ownership rights of certain properties or resources, including with respect to the validity of oil and gas leases held by the Corporation or with respect to the calculation or deduction of royalties payable on the Corporation's production. The existence of title defects or the resolution of disputes may have a material adverse effect on the Corporation or its assets and operations. Furthermore, from time to time, the Corporation or its industry partners may owe one another contractual, trust related or offset obligations which they may default in satisfying and which may adversely affect the validity of an oil and gas lease in which the Corporation has an interest. The existence of title defects, unsatisfied contractual or trust related obligations, including offset obligations, or the resolution of any disputes with industry partners arising from same, may have a material adverse effect on the Corporation or its assets and operations.

The Corporation may be unable to compete successfully with other organizations in the oil and natural gas industry.

The oil and natural gas industry is highly competitive. The Corporation competes for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity, and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of these organizations not only explore for, develop and produce oil and natural gas, but also conduct refining operations and market oil and other products on a world-wide basis. As a result of these complementary activities, some of the Corporation's competitors may have greater and more diverse resources to draw upon.

The Corporation may be at a competitive disadvantage to other industry participants, such as pension resource corporations, U.S. flow-through entities, such as master limited partnerships and limited liability companies, and U.S. or other foreign corporations that are able to minimize Canadian tax through the use of inter-company debt, and cross-border tax planning measures, or who have access to lower cost of capital.

The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities.

GENERAL

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation in Canada and federal and state laws and regulations in the United States. A breach of that legislation may result in the imposition of fines or the issuance of "clean up" orders. Legislation regulating the Corporation's industry may be changed to impose higher standards and potentially more costly obligations, such as legislation that would require significant reductions in greenhouse gas emissions. Failure to comply with such regulations and laws can result in significant increases in costs, penalties or loss of operating licenses. Further, the business of exploration, development and production operation of oil and natural gas wells and facilities is subject to the risks and hazards associated with such operations. These include, but are not limited to, blowouts, fire, explosion, environmental releases, including sour gas, and other safety hazards which could result in significant damage to the Corporation's property, personal injury, loss of life and liability to regulators or third parties. Although the actual form such legislation or regulation may take is largely unknown at this time, the implementation of more stringent environmental legislation or regulatory requirements may result in additional costs for oil and natural gas producers such as the Corporation, and such costs may be significant.

The Corporation is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, the Corporation's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons.

The Corporation does not establish a separate reclamation fund for the purpose of funding its estimated future environmental and reclamation obligations. The Corporation cannot assure investors that it will be able to satisfy its future environmental and reclamation obligations. Any site reclamation or abandonment costs incurred in the ordinary course, in a specific period, will be funded out of cash flows and, therefore, will reduce the amounts that may be available to pay as dividends to shareholders. Should the Corporation be unable to fully fund the cost of remedying an environmental claim, the Corporation might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

RISKS RELATING TO FRACTURING

The Corporation utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated drilling fluids and other technologies in connection with its drilling and completion activities. There has been public concern over the hydraulic fracturing process. Most of these concerns have raised questions regarding the drilling fluids used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations, the ability of such water to be recycled, and induced seismicity associated with fracturing. The U.S. and Canadian federal governments and certain U.S. state and Canadian provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in certain of the jurisdictions in which the Corporation operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. However, certain environmental and other groups have suggested that additional federal, provincial, territorial, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity particularly where in proximity to pre-existing faults. In addition, the U.S. EPA has commenced a study of the potential environmental impacts of hydraulic fracturing, including the impacts on drinking water sources and public health. Further, certain governments in jurisdictions where the Corporation does not currently operate have considered a temporary moratorium on hydraulic fracturing until further studies can be completed and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations.

It is anticipated that federal, provincial and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While the Corporation is unable to predict the impact of any potential regulations upon its business, the implementation of new laws, regulations or permitting regulations with respect to water usage or hydraulic fracturing generally could increase the Corporation's costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact the Corporation's production and prospects, any of which may have a material adverse effect on the Corporation's business, financial condition and results of operations.

The Corporation's expanded scope of activities and enlarged shareholder base may attract increased criticism and costly litigation.

The expansion of the Corporation's business activities, both geographically and with a new focus on exploration, may draw increased attention from special interest groups opposed to the Corporation, its business or its plans for development, which could have an adverse effect on market value. Higher visibility among investors may expose the Corporation to greater risk of class action lawsuits related to, among other things, securities, title, contractual and environmental matters.

Changes in laws, including those affecting tax, royalties and other financial matters, and interpretations of those laws, may adversely affect the Corporation and its securityholders.

Tax laws, including those that may affect the taxation of the Corporation or the Corporation's dividends to its shareholders, or other laws or government incentive programs relating to the oil and gas industry, may be changed or interpreted in a manner that adversely affects the Corporation and its securityholders. Canadian, U.S. and foreign tax authorities having jurisdiction over the Corporation (whether as a result of the Corporation's operations or financing structures) or its securityholders may change or interpret applicable tax laws or treaties or administrative positions in a manner which is detrimental to the Corporation or its securityholders, or may disagree with how the Corporation calculates its income for tax purposes. Additionally, the Corporation may be subject to additional taxation or royalty payments imposed by government and tribal authorities that have jurisdiction over its Fort Berthold properties, including as a result of the adoption of major portion pricing methodologies measures. The Corporation has income tax filings that are subject to audit and potential reassessment which may impact the Corporation's tax liability. The Corporation believes appropriate provisions for current and deferred income taxes have been made in its financial statements; however, it is difficult to predict the outcome of audit findings by tax authorities. These findings may increase the amount of its tax liabilities and be detrimental to the Corporation.

If the Corporation expands beyond its current areas of operations or expands the scope of operations beyond oil and natural gas production, the Corporation may face new challenges and risks. If the Corporation is unsuccessful in managing these challenges and risks, its results of operations and financial condition could be adversely affected.

The Corporation may acquire oil and natural gas properties and assets outside the geographic areas in which it has historically conducted its business and operations. The expansion of the Corporation's activities into new locations may present challenges and risks that the Corporation has not faced in the past, including operational and additional regulatory matters. The Corporation's failure to manage these challenges and risks successfully may adversely affect results of operations and financial condition. In addition, the Corporation's activities are not limited to oil and natural gas production and development, and the Corporation could acquire other energy related assets. Expansion of the Corporation's activities into new areas may present challenges and risks that it has not faced in the past, including dealing with additional regulatory matters. If the Corporation does not manage these challenges and risks successfully, its results of operations and financial condition could be adversely affected.

The Corporation sets out to hire competent personnel and the loss of such personnel, including the Corporation's key management, could impact its business.

Shareholders are entirely dependent on the management of the Corporation with respect to the exploration for and development of additional reserves and resources, the acquisition of oil and natural gas properties and assets and the management and administration of all matters relating to the Corporation and its properties and assets, including hiring competent personnel. The loss of the services of competent personnel and key individuals could have a detrimental effect on the Corporation. Further, the Corporation's acquisitions and activities in various play types require different skill sets than those needed in developing its mature income-oriented assets. There is no assurance that the Corporation will be able to attract and retain personnel with the technical expertise and competence necessary to develop such properties, which could adversely affect the Corporation's exploration and development plans.

Conflicts of interest may arise between the Corporation and its directors and officers.

Circumstances may arise where directors and officers of the Corporation are directors or officers of corporations or other entities involved in the oil and gas industry which are in competition to the interests of the Corporation. See "*Directors and Officers – Conflicts of Interest*". No assurances can be given that opportunities identified by such persons will be provided to the Corporation.

Changes in market-based factors may adversely affect the trading price of the Common Shares.

The market price of the Common Shares is primarily a function of the value of the properties owned by the Corporation and anticipated dividends paid to its shareholders. The market price of the Common Shares is therefore sensitive to a variety of market-based factors, including, but not limited to, the inclusion, or removal, of our stock from one or more stock market indexes or exchange traded funds, interest rates and the comparability of the Common Shares to other yield-oriented securities and exploration and production companies. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

The Corporation's information assets and critical infrastructure may be subject to cyber security risks.

The Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Although the Corporation has security measures in place that are designed to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and a disruption to its business activities. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

United States and other non-resident shareholders may be subject to additional taxation.

The Tax Act and the tax treaties between Canada and other countries may impose withholding or other taxes on the cash dividends, stock dividends or other property paid by the Corporation to shareholders who are not residents of Canada, and these taxes may change from time to time. In addition, the country in which the shareholder is resident may impose additional taxes on such dividends and these taxes may change from time to time.

Non-resident shareholders are subject to foreign exchange risk on the dividends that they may receive from the Corporation.

Any dividends that may be declared by the Corporation from time to time are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar weakens with respect to their currency, the amount of the dividend will be reduced when converted to their home currency.

The ability of United States and other non-resident shareholder investors to enforce civil remedies may be limited.

The Corporation is formed under the laws of Alberta, Canada, and its principal place of business is in Canada. Most of the directors and officers of the Corporation are residents of Canada and some of the experts who provide services to the Corporation (such as its auditors and some of its independent reserves engineers) are residents of Canada, and all or a substantial portion of their assets and the Corporation's assets are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "**Foreign Jurisdiction**") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgments of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including U.S. federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against the Corporation or any of its directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of U.S. courts of liabilities based solely upon the U.S. federal securities laws or the securities laws of any state within the United States.

Market for Securities

The Common Shares are listed and posted for trading on the TSX and the NYSE under the trading symbol "ERF".

The following table sets forth certain trading information for the Common Shares on the TSX composite index and the United States composite index information for 2014.

	TSX Composite Trading			U.S. Composite Trading		
Month	**High**	**Low**	**Volume**	**High**	**Low**	**Volume**
January	20.61	18.45	17,521,200	18.61	17.15	11,946,242
February	22.37	19.47	20,671,270	20.18	17.54	12,713,685
March	22.23	20.23	20,036,300	20.17	18.17	10,524,886
April	24.79	21.54	19,426,581	22.63	19.58	11,397,319
May	24.72	22.02	18,731,878	22.80	20.18	11,549,043
June	26.92	24.42	30,161,487	25.24	22.41	13,721,975
July	27.05	24.60	27,258,168	25.37	22.73	11,473,912
August	25.07	23.28	18,395,924	22.95	21.32	10,976,907
September	24.85	20.21	35,408,782	22.79	18.45	17,224,178
October	21.32	15.74	36,093,532	19.08	13.92	24,448,509
November	18.36	14.43	36,230,373	16.35	12.67	25,948,448
December	15.39	9.02	80,869,197	13.52	7.75	42,039,814

Directors and Officers

DIRECTORS OF THE CORPORATION

The directors of the Corporation are elected by the shareholders of the Corporation at each annual meeting of shareholders. All directors serve until the next annual meeting or until a successor is elected or appointed or until the director is removed at a meeting of shareholders. The name, municipality of residence, year of appointment as a director of the Corporation (or its predecessor EnerMark Inc., the administrator of the Fund prior to the Conversion) and principal occupation for the past five years for each current director of the Corporation are set forth below.

Name and Residence	Director Since	Principal Occupation for Past Five Years
Elliott Pew[(1)] Boerne, Texas, United States	September 2010	Director of Common Resources III, L.L.C., a private oil and gas company, since May 2010, and Southwestern Energy Company, an NYSE-listed oil and gas company since July 2012. Prior thereto, a director of Common Resources II, L.L.C., a private oil and gas company, from May 2010 to August 2012. Prior thereto, Chief Operating Officer of Common Resources L.L.C., a private oil and gas company, from March 2007 to May 2010.
David H. Barr[(6)] Woodlands, Texas, United States	July 2011	Director of Logan International Inc., a TSX-listed company focused on downhole tools and completion services. Prior thereto, President and Chief Executive Officer and, prior thereto, the Chairman of the board of directors, of Logan International Inc., a TSX listed oil and gas services company, since March 1, 2011. Prior thereto, Group President of various divisions of Baker Hughes Incorporated, an NYSE-listed oilfield services company.
Michael R. Culbert[(3)(4)] Calgary, Alberta, Canada	March 2014	Mr. Culbert is President and Chief Executive Officer and a director of Progress Energy Canada Ltd., an oil and gas company, since January 2009.
Edwin V. Dodge[(4)(6)(7)] Vancouver, British Columbia, Canada	May 2004	Corporate director.
Ian C. Dundas Calgary, Alberta, Canada	July 2013	President & Chief Executive Officer of Enerplus since July 2013. Prior thereto, Executive Vice-President and Chief Operating Officer of Enerplus from April 2011 to July 2013 and prior thereto, Senior Vice-President, Business Development of Enerplus from August 2010.
Hilary A. Foulkes[(2)(6)] Calgary, Alberta, Canada	February 2014	Corporate Director. Prior thereto, Executive Vice President and Chief Operating Officer of Penn West Petroleum Ltd., a TSX and NYSE-listed oil and gas company, from 2011 to 2012. Prior thereto, Senior Vice President of Business Development of Penn West Petroleum Ltd. from 2008 to 2010.
James B. Fraser[(5)(6)] Polson, Montana, United States	June 2012	Corporate director since June 2012. Currently a Managing Partner of Source Rock Energy Partners LLC, a private equity firm, since 2014. Prior thereto, Senior Vice President for the shale division of Talisman Energy Inc., a TSX and NYSE-listed oil and gas company, from September 2008 until April 2012.
Robert B. Hodgins[(2)(3)(8)] Calgary, Alberta, Canada	November 2007	Independent businessman.
Susan M. MacKenzie[(4)(5)] Calgary, Alberta, Canada	July 2011	Independent consultant since September 2010. Prior thereto, Chief Operating Officer of Oilsands Quest Inc., an NYSE Amex-listed oil sands company through August 2010. Prior thereto, various senior managerial positions with Petro-Canada, a TSX and NYSE-listed integrated oil and gas company prior to its merger with Suncor Energy Inc. in 2009.
Donald J. Nelson[(3)(4)(7)] Calgary, Alberta, Canada	June 2012	President of Fairway Resources Inc., a private oil and gas consulting services firm.
Glen D. Roane[(2)(3)] Canmore, Alberta, Canada	June 2004	Corporate director.
Sheldon B. Steeves[(2)(5)] Calgary, Alberta, Canada	June 2012	Corporate Director. From January 2001 until April 2012, Chairman and Chief Executive Officer of Echoex Ltd., a junior private oil and gas company.

Notes:

(1) Chairman of the board of directors and ex officio member of all committees of the board of directors.

(2) The Audit & Risk Management Committee is currently comprised of Robert B. Hodgins as Chairman, Hilary A. Foulkes, Glen D. Roane and Sheldon B. Steeves.
(3) The Corporate Governance & Nominating Committee is currently comprised of Glen D. Roane as Chairman, Michael R. Culbert, Robert B. Hodgins and Donald J. Nelson.
(4) The Compensation & Human Resources Committee is currently comprised of Susan M. MacKenzie as Chairman, Michael R. Culbert, Edwin V. Dodge and Donald J. Nelson.
(5) The Reserves Committee is currently comprised of Sheldon B. Steeves as Chairman, James B. Fraser and Susan M. MacKenzie.
(6) The Safety & Social Responsibility Committee is currently comprised of David H. Barr as Chairman, Edwin V. Dodge, Hilary A. Foulkes and James B. Fraser.
(7) Messrs. Dodge and Nelson are not standing for re-election at the 2015 annual meeting of shareholders of the Corporation.
(8) Mr. Hodgins was a director of Skope Energy Inc. ("**Skope**") in November 2012 when Skope entered into a settlement agreement with Pine Cliff Energy Ltd. ("**Pine Cliff**") and filed for protection under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**"). A plan for compromise and arrangement under the CCAA filed by Pine Cliff and Skope was accepted by the Court of Queen's Bench of Alberta on January 15, 2013, received the requisite approval of Skope's creditors on February 15, 2013 and came into effect on February 20, 2013. Mr. Hodgins resigned as a director of Skope on February 19, 2013.

OFFICERS OF THE CORPORATION

The name, municipality of residence, position held and principal occupation for the past five years for each officer of the Corporation are set out below.

Name and Residence	Office	Principal Occupation for Past Five Years
Ian C. Dundas Calgary, Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of the Corporation since July 1, 2013. Prior thereto, Executive Vice President & Chief Operating Officer of the Corporation since April 2011. Prior thereto, Executive Vice President, Enerplus since March 2010. Prior thereto, Senior Vice President, Business Development of Enerplus.
Robert J. Waters Calgary, Alberta, Canada	Senior Vice President & Chief Financial Officer	Senior Vice President & Chief Financial Officer of Enerplus.
Raymond J. Daniels Calgary, Alberta, Canada	Senior Vice President, Operations	Senior Vice President, Operations of the Corporation since May 2012. Prior thereto, Senior Vice President, Canadian Operations of the Corporation since April 2011. Prior thereto, Vice President, Development Services of Enerplus.
Eric G. Le Dain Calgary, Alberta, Canada	Senior Vice President, Corporate Development, Commercial	Senior Vice President, Corporate Development, Commercial of the Corporation since July 2013. Prior thereto, Senior Vice President, Strategic Planning, Reserves & Marketing of the Corporation since April 2011. Prior thereto, Vice President, Strategic Planning, Reserves & Marketing of Enerplus since March 2010. Prior thereto, Vice President, Regulatory, Environment and Marketing of Enerplus since December 2008.
Jo-Anne M. Caza Calgary, Alberta, Canada	Vice President, Corporate & Investor Relations	Vice President, Corporate & Investor Relations of Enerplus.
Jodine J. Jenson Labrie Calgary, Alberta, Canada	Vice President, Finance	Vice President, Finance of the Corporation since July 2013. Prior thereto, Ms. Jenson Labrie held various positions of increasing responsibility since joining Enerplus in 2003, including Controller, Finance and Senior Manager, Planning & Marketing.
Robert A. Kehrig Calgary, Alberta, Canada	Vice President, Business Development & New Plays	Vice President, Business Development & New Plays of the Corporation since February 2013. Prior thereto, Vice President, Resource Development of Enerplus since November 2008.
David A. McCoy Calgary, Alberta, Canada	Vice President, General Counsel & Corporate Secretary	Vice President, General Counsel & Corporate Secretary of Enerplus.
Edward L. McLaughlin Denver, Colorado, United States	President, U.S. Operations	President, U.S. Operations of the Corporation since May 2012. Prior thereto, Manager of Land of Enerplus USA since joining the Corporation in November 2011. Prior thereto, Vice President, Corporate Development of Venoco, Inc., an NYSE-listed energy company, from November 2010 to November 2011 and as Manager of Land of FIML Natural Resources, a U.S. private exploration and production company, from June to November 2010. Prior thereto, President of Petro-Canada Resources (USA) Inc., a U.S. subsidiary of Petro-Canada, a TSX and NYSE-listed oil and gas company, prior to its merger with Suncor Energy Inc. in 2009.

Name and Residence	Office	Principal Occupation for Past Five Years
Lisa M. Ower Calgary, Alberta, Canada	Vice President, Human Resources	Vice President, Human Resources of the Corporation since May 2014. Prior to joining Enerplus, Ms. Ower held positions as Vice President, Human Resources and Administrative Services at Veresen Inc., a TSX-listed energy infrastructure company, from May 2013 to May 2014, Vice President, Global Talent Management at Talisman Energy Inc., a TSX and NYSE-listed oil and gas company, from September 2011 to May 2013, and Global Head of Talent Management at Celestica Inc., a TSX and NYSE-listed integrated global supply chain company from January 2008 to September 2011.
P. Scott Walsh Airdrie, Alberta, Canada	Vice President, Information & Corporate Services	Vice President, Information and Corporate Services of the Corporation since February 2014. Prior thereto, Vice President, Information Systems of the Corporation since April 2011. Prior thereto, Corporate Director, Information Services – Infrastructure and Application & Infrastructure with Suncor Energy Inc. Prior thereto, various management positions with Suncor Energy Inc.
Kenneth W. Young Calgary, Alberta, Canada	Vice President, Land & Operations Services	Vice President, Land & Operations Services of the Corporation since December 2014. Prior thereto, Vice President, Land of the Corporation from August 2010 to December 2014.
Michael R. Politeski Calgary, Alberta, Canada	Treasurer & Corporate Controller	Treasurer & Corporate Controller of the Corporation since July 2013. Prior thereto, Controller, Finance of the Corporation since August 2012. Prior thereto, Manager, Finance of Enerplus.

COMMON SHARE OWNERSHIP

As of February 13, 2015, the directors and officers of the Corporation named above beneficially own, or control or exercise direction over, directly or indirectly, an aggregate of 402,462 Common Shares, representing approximately 0.2% of the outstanding Common Shares as of that date.

CONFLICTS OF INTEREST

Certain of the directors and officers named above may be directors or officers of issuers which are in competition with the Corporation, and as such may encounter conflicts of interests in the administration of their duties with respect to the Corporation. In situations where conflicts of interest arise, the Corporation expects the applicable director or officer to declare the conflict and, if a director of the Corporation, abstain from voting in respect of such matters on behalf of the Corporation.

See "*Risk Factors – Conflicts of interest may arise between the Corporation and its directors and officers*".

AUDIT & RISK MANAGEMENT COMMITTEE DISCLOSURE

The disclosure regarding the Corporation's Audit & Risk Management Committee required under National Instrument 52-110 adopted by the Canadian securities regulatory authorities is contained in Appendix C to this Annual Information Form.

Legal Proceedings and Regulatory Actions

The Corporation is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Corporation's favour, the Corporation does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Corporation may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operation or liquidity. The Corporation is not and was not during 2014 a party to, and none of the Corporation's property is or was during 2014 the subject of, any legal proceeding that involves a claim for damages (exclusive of interest and costs) greater than 10% of its current assets as at December 31, 2014, and the Corporation has no knowledge of any such proceeding being contemplated.

Interest of Management and Others in Material Transactions

To the knowledge of the directors and executive officers of the Corporation, none of the directors or executive officers of the Corporation and no 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 the Corporation's securities, nor any associate or affiliate of any of the foregoing, has had any material interest, direct or indirect, in any transaction with the Corporation since January 1, 2012 or in any proposed transaction that has materially affected or is reasonably expected to materially affect Enerplus.

Material Contracts and Documents Affecting the Rights of Securityholders

The Corporation is not a party to any contracts material to its business or operations, other than contracts entered into in the normal course of business.

Copies of the following documents entered into the normal course of business and relating to the Credit Facilities have been filed on the Fund's SEDAR profile at www.sedar.com and on Form 6-K on the Fund's EDGAR profile at www.sec.gov, if they were filed prior to the January 1, 2011 Conversion, and on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov, if they were filed on or after the January 1, 2011 Conversion:

1. Amended and Restated Bank Credit Facility (November 5, 2012), the First Amending Agreement relating thereto (January 13, 2014), the Second Amending Agreement relating thereto (May 13, 2014) and the Third Amending Agreement relating thereto (SEDAR – December 1, 2014; EDGAR – December 9, 2014);
2. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2003, together with the First Amendment (March 18, 2008);
3. Second Amendment to the Note Purchase Agreement for the Senior Unsecured Notes issued in 2003 (SEDAR – November 10, 2010; EDGAR – November 12, 2010);
4. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2009 (SEDAR – June 23, 2009; EDGAR – June 25, 2009);
5. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2012 (SEDAR – May 23, 2012; EDGAR – May 24, 2012); and
6. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2014 (SEDAR – October 10, 2014; EDGAR – October 15, 2014).

Copies of the following documents affecting the rights of securityholders have been filed on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov, as they were filed after the January 1, 2011 Conversion:

1. the Articles of Amalgamation (January 2, 2013) and bylaws of the Corporation (June 16, 2014); and
2. the Shareholder Rights Plan, as described under "*Description of Capital Structure – Shareholder Rights Plan*" (May 10, 2013).

Interests of Experts

McDaniel prepared the McDaniel Reports in respect of certain reserves attributable to the Corporation's oil and natural gas properties in Canada and the western United States, a summary of which is contained in this Annual Information Form, and reviewed certain reserves evaluated internally by the Corporation. McDaniel also audited the estimate of contingent resources attributable to the Corporation's interests in the Fort Berthold, North Dakota area, and its Wilrich natural gas assets located in Alberta, which is referred to in this Annual Information Form. As of the dates of the McDaniel Reports, the "designated professionals" (as defined in Form 51-102F2 – *Annual Information Form* of the Canadian securities regulatory authorities) of McDaniel, as a group, beneficially owned, directly or indirectly, less than 1% of the outstanding Common Shares. NSAI prepared the NSAI Report in respect of the reserves and contingent resources attributable to the Corporation's interests in the Marcellus property, a summary of which is contained in this Annual Information Form. As of the dates of the NSAI Report, the designated professionals of NSAI, as a group, beneficially owned, directly or indirectly, less than 1% of the outstanding Common Shares.

The independent registered public accounting firm of the Corporation is Deloitte LLP ("Deloitte"), Chartered Accountants, Calgary, Canada. Deloitte has confirmed that it is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta, and the applicable rules and regulations thereunder adopted by the SEC and the Public Company Accounting Oversight Board (United States).

Transfer Agent and Registrar

The transfer agent and registrar for the Common Shares in Canada is Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario. Computershare Trust Company N.A. at its principal offices in Golden, Colorado is the transfer agent for the Common Shares in the United States.

Additional Information

Additional information relating to the Corporation may be found on the Corporation's profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and on the Corporation's website at www.enerplus.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, as applicable, will be contained in the Corporation's information circular and proxy statement with respect to its 2015 annual meeting of shareholders. Furthermore, additional financial information relating to the Corporation is provided in the Corporation's audited consolidated financial statements and MD&A for the year ended December 31, 2014. Shareholders who wish to receive printed copies of these documents free of charge should contact the Corporation's Corporate & Investor Relations Department using the contact information on the back cover of this Annual Information Form.

Appendix A – Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

To the board of directors of Enerplus Corporation (the "Corporation"):

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

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

   We carried out our evaluation and review, as applicable, 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 and review, as applicable, to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review 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 discount rate of 10 percent, included in the reserves data of the Corporation evaluated and reviewed, as applicable, by us, for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reviewed, as applicable, and reported on the Corporation's Management:

Independent Qualified Reserves Evaluator	Preparation Date of Evaluation or Review Report	Location of Reserves	Net Present Value of Future Net Revenue			
			Audited	Evaluated	Reviewed	Total
			(before income taxes, 10% discount rate) (in $ thousands)			
McDaniel & Associates Consultants Ltd.	January 28, 2015	Canada	–	$1,181,866.2	$477,038.9	$1,658,905.1
McDaniel & Associates Consultants Ltd	January 28, 2015	North Dakota & Montana, USA	–	US$1,743,107.0	–	US$1,743,107.0
Netherland, Sewell & Associates, Inc.	January 20, 2015	Pennsylvania & West Virginia, USA	–	US$ 576,235.2	–	US$ 576,235.2

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. 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 reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"*signed by P.A. Welch*"

P.A. Welch, P.Eng.
President & Managing Director

Calgary, Alberta, Canada
January 28, 2015

NETHERLAND, SEWELL & ASSOCIATES, INC.

"*signed by C.H. (Scott) Rees III*"

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Texas Registered Engineering Firm F-2699
Dallas, Texas USA
February 6, 2015

APPENDIX B

Appendix B – Report of Management and Directors on Oil and Gas Disclosure

Terms to which a meaning is described in CSA Staff Notice 51- 324 – Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Enerplus Corporation (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, 2014, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated and reviewed the Corporation's reserves data. The reports of the independent qualified reserves evaluators are presented as Appendices A and B to this Annual Information Form.

The Reserves Committee of the board of directors of the Corporation has:

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

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

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

The Reserves Committee of the board of directors of the Corporation 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 of the Corporation has, on the recommendation of the Reserves Committee, approved:

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

(b) the filing of Forms 51-101F2 which are the reports of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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

ENERPLUS CORPORATION

"*Ian C. Dundas*"

Ian C. Dundas
President & Chief Executive Officer

"*Eric G. Le Dain*"

Eric G. Le Dain
Senior Vice President, Corporate Development, Commercial

"*Elliott Pew*"

Elliott Pew
Director

"*Sheldon B. Steeves*"

Sheldon B. Steeves
Director

February 20, 2015

APPENDIX C

Appendix C – Audit & Risk Management Committee Disclosure Pursuant to National Instrument 52-110

A. THE AUDIT & RISK MANAGEMENT COMMITTEE'S CHARTER

The charter of the Audit & Risk Management Committee (the "**Committee**") of the board of directors of the Corporation is attached as Schedule 1 to this Appendix C.

B. COMPOSITION OF THE AUDIT & RISK MANAGEMENT COMMITTEE

The current members of the Committee are Robert B. Hodgins (Chairman), Hilary A. Foulkes, Glen D. Roane and Sheldon B. Steeves. Each member of the Committee is independent and financially literate within the meaning of National Instrument 52-110.

C. RELEVANT EDUCATION AND EXPERIENCE

Name (Director Since)	Principal Occupation and Biography
Robert B. Hodgins (Honors B.A. (Business), C.A.) (Director since November 2007) Other Public Directorships • AltaGas Ltd. (energy midstream services) • Contact Exploration Inc. (oil and gas exploration and production company) • Cub Energy Inc. (oil and gas exploration and production company) • Kicking Horse Energy Inc. (oil and gas exploration and production company) • MEG Energy Corp. (oil sands company) • StonePoint Energy Inc. (oil and gas exploration and production company)	Mr. Hodgins has been an independent businessman since November 2004. Prior to that, Mr. Hodgins served as the Chief Financial Officer of Pengrowth Energy Trust (a TSX and NYSE-listed energy trust) from 2002 to 2004. Prior to that, Mr. Hodgins held the position of Vice President and Treasurer of Canadian Pacific Limited (a diversified energy, transportation and hotels company) from 1998 to 2002 and was Chief Financial Officer of TransCanada PipeLines Limited (a TSX and NYSE-listed energy transportation company) from 1993 to 1998. Mr. Hodgins received an Honors Bachelor of Arts in Business from the Richard Ivey School of Business at the University of Western Ontario in 1975 and received a Chartered Accountant designation and was admitted as a member of the Institute of Chartered Accountants of Ontario in 1977 and Alberta in 1991.
Hilary A. Foulkes (B.Sc., Honours (Earth Sciences)) (Director since February 2014) Other Public Directorships • Parallel Energy Trust (oil and gas exploration and production entity)	Ms. Foulkes has over 30 years of oil and gas industry experience and is currently a director of Parallel Energy Trust, a TSX-listed oil and gas energy trust. From 2008 to 2012, Ms. Foulkes held a number of executive roles at Penn West Petroleum Ltd., a TSX and NYSE-listed oil and gas company, including Executive Vice President and Chief Operating Officer. Prior thereto, Ms. Foulkes was Managing Director at Scotia Waterous, an investment banking firm, from April 2000 to March 2008. Ms. Foulkes holds an Honours Bachelor of Science degree in Earth Sciences from the University of Waterloo, is a professional geologist, and a member of the Association of Professional Engineers and Geoscientists of Alberta and Canadian Association of Petroleum Geologists.

Name (Director Since)	Principal Occupation and Biography
Glen D. Roane (B.A., MBA) (Director since June 2004) Other Public Directorships • Badger Daylighting Ltd. (provider of non-destructive excavation services) • Logan International Inc. (oil and gas service business) • SilverWillow Energy Corporation (oil sands company)	Mr. Roane is a corporate director and has served as a board member of many TSX-listed companies including (in addition to those public entities listed herewith of which he currently serves as a director) UTS Energy Corporation, Repap Enterprises Inc., Ranchero Energy Inc., Forte Resources Inc., Valiant Energy Inc., Maxx Petroleum Ltd. and NQL Energy Services Inc., since his retirement from TD Asset Management Inc., a subsidiary of The Toronto-Dominion Bank (a publicly traded Canadian chartered bank) in 1997. In addition to serving as a director of the public entities listed herewith, Mr. Roane is a director of GBC North American Fund Inc., a Canadian mutual fund corporation. Mr. Roane is also a member of the Alberta Securities Commission. Mr. Roane holds a Bachelor of Arts and an MBA from Queen's University in Kingston, Ontario. Mr. Roane also holds the ICD.D designation from the Institute of Corporate Directors.
Sheldon B. Steeves (B.Sc. (Geology)) (Director since June 2012) Other Public Directorships • NuVista Energy Ltd. (oil and gas exploration and production company) • PrairieSky Royalty Ltd. (oil and gas royalty focused company)	Mr. Steeves has over 37 years of experience in the North American oil and gas industry and is currently a director of NuVista Energy Ltd., a TSX-listed Canadian oil and gas company with operations in the Western Canadian Sedimentary Basin and of PrairieSky Royalty Ltd., a TSX-listed Canadian oil and gas royalty focused company. From January 2001 until April 2012, Mr. Steeves was Chairman and Chief Executive Officer of Echoex Ltd., a junior oil and gas private company focused on greenfield organic growth in Western Canada. Mr. Steeves spent over 15 years at Renaissance Energy Ltd., where he was appointed Chief Operating Officer in 1997. Mr. Steeves holds a Bachelor of Science in Geology from the University of Calgary.

D. PRE-APPROVAL POLICIES AND PROCEDURES

The Committee has implemented a policy restricting the services that may be provided by the Corporation's auditors and the fees paid to the Corporation's auditors. Prior to the engagement of the Corporation's auditors to perform both audit and non-audit services, the Committee pre-approves the provision of the services. In making their determination regarding non-audit services, the Committee considers the compliance with the policy and the provision of non-audit services in the context of avoiding impact on auditor independence. All audit and non-audit fees paid to Deloitte in 2014 and 2013 were pre-approved by the Committee. Based on the Committee's discussions with management and the independent auditors, the Committee is of the view that the provision of the non-audit services by Deloitte described above is compatible with maintaining that firm's independence from the Corporation.

E. EXTERNAL AUDITOR SERVICE FEES

The aggregate fees paid by the Corporation to Deloitte, Independent Registered Chartered Accountants, the independent auditor of Enerplus, for professional services rendered in Enerplus' last two fiscal years are as follows:

		2014		2013
		(in $ thousands)		
Audit fees(1)	**$**	**783.0**	$	965.9
Audit-related fees(2)		**–**		–
Tax fees(3)		**351.6**		500.5
All other fees(4)		**–**		–
	$	**1,134.6**	$	1,466.4

Notes:

(1) Audit fees were for professional services rendered by Deloitte for the audit of the Corporation's annual financial statements and reviews of the Corporation's quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees are for assurance and related services reasonably related to the performance of the audit or review of the Corporation's financial statements and not reported under "Audit fees" above.

(3) Tax fees were for tax compliance, tax advice and tax planning.

(4) All other fees are fees for products and services provided by the Corporation's auditors other than those described as "Audit fees", "Audit-related fees" and "Tax fees".

Audit & Risk Management Committee Charter

I AUTHORITY

The Audit & Risk Management Committee (the "Committee") of the Board of Directors (the "Board") of the Enerplus Corporation (the "Corporation") shall be comprised of three or more Directors as determined from time to time by resolution of the Board. Consistent with the appointment of other Board committees, the members of the Committee shall be elected by the Board at the first meeting of the Board following each annual meeting of Shareholders of the Corporation or at such other time as may be determined by the Board. The Chair of the Committee shall be designated by the Board, provided that if the Board does not so designate a Chair, the members of the Committee, by majority vote, may designate a Chair. The presence in person or by telephone of a majority of the Committee's members shall constitute a quorum for any meeting of the Committee. All actions of the Committee will require the vote of a majority of its members present at a meeting of the Committee at which a quorum is present.

Members of the Committee do not receive any compensation from the Corporation other than compensation as directors and committee members. Prohibited compensation includes fees paid, directly or indirectly, for services as consultant or as legal or financial advisor, regardless of the amount, but excludes any compensation approved by the Board and that is paid to the directors as members of the Board and its committees.

II PURPOSE OF THE COMMITTEE

The Committee's mandate is to assist the Board in fulfilling its oversight responsibilities with respect to:

1. financial reporting and continuous disclosure of the Corporation;
2. the Corporation's internal controls and policies, the certification process and compliance with regulatory requirements over financial matters;
3. evaluating and monitoring the performance and independence of the Corporation's external auditors; and
4. monitoring the manner in which the business risks of the Corporation are being identified and managed.

The Committee shall report to the Board on a regular basis with regard to such matters. The Committee has direct responsibility to recommend the appointment of the external auditors and approve their remuneration. The Committee may take such actions, as it deems necessary to satisfy itself that the Corporation's auditors are independent of management. It is the objective of the Committee to maintain free and open means of communications (including the annual proxy information circular) among the Board, the external auditors, and the financial senior management of the Corporation.

III COMPOSITION AND COMPETENCY OF THE COMMITTEE

Each member of the Committee shall be unrelated to the Corporation and, as such, shall be free from any relationship that may interfere with the exercise of his or her independent judgement as a member of the Committee. All members of the Committee shall be financially literate and at least one member of the Committee shall have accounting or related financial management expertise – "literate" or "literacy" and "expertise" as defined by applicable securities legislation. Members are encouraged to enhance their understanding of current issues through means of their preference.

IV MEETINGS OF THE COMMITTEE

The Committee shall meet with such frequency and at such intervals as it shall determine is necessary to carry out its duties and responsibilities. As part of its purpose to foster open communications, the Committee shall meet at least quarterly with management and the Corporation's external auditors in separate executive sessions to discuss any matters that the Committee or each of these groups, or persons, believes should be discussed privately. The Chair works with the Chief Financial Officer and external auditors to establish the agendas for Committee meetings, ensuring that each party's expectations are understood and addressed. The Committee, in its discretion, may ask members of management or others to attend its meetings (or portions thereof) and to provide pertinent information as necessary. The Committee shall maintain minutes of its meetings and records relating to those meetings and the Committee's activities and provide copies of such minutes to the Board.

V DUTIES AND ACTIVITIES OF THE COMMITTEE

Evaluating and monitoring the performance and independence of external auditors

1. Make recommendations to the Board on the appointment of external auditors of the Corporation;
2. Review and approve the Corporation's external auditors' annual engagement letter, including the proposed fees contained therein;
3. Review the performance of the external auditors and make recommendations to the Board regarding their replacement when circumstances warrant. The review shall take into consideration the evaluation made by management of the external auditors' performance and shall include.
   a) Review annually the external auditors' quality control, any material issues raised by the most recent quality control review, or peer review, of the firm, or any inquiry or investigation by governmental or professional authorities of the firm within the preceding five years, and any steps taken to deal with such issues;
   b) Obtain assurances from the external auditors that the audit was conducted in accordance with Canadian and U.S. generally accepted auditing standards; and
   c) Ensure that management interacts professionally with the auditors and confirm such behavior annually with both parties.
4. Oversee the independence of the external auditors by, among other things:
   a) requiring the external auditors to deliver to the Committee on a periodic basis a formal written statement detailing all relationships between the external auditors and the Corporation;
   b) reviewing and approving the Corporation's hiring policies regarding partners, employees and former partners and employees of current and former external auditors;
   c) actively engaging in a dialogue with the external auditors with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditors and recommending that the Board take appropriate action to satisfy itself of the auditors' independence.
   d) pre-approve the nature of non-audit related services and the fees thereon;
   e) conducting private sessions with the external auditors and encouraging direct communications between the Chair of the Committee and the audit partner;
   f) instructing the Corporation's external auditors that they are ultimately accountable to the Committee and the Board and that the Committee and the Board are responsible for the selection (subject to Shareholder approval), evaluation and termination of the Corporation's external auditors;
   g) having a private meeting with the external auditors at every quarterly Committee meeting; and
   h) obtaining annually the auditors' views on competency and integrity of the audit committee and senior financial executives;

Oversight of annual and quarterly financial statements, management discussion and analysis and press releases

5. Review and approve the annual audit plan of the external auditors, including the scope of audit activities, and monitor such plan's progress and results quarterly and at year end;
6. Confirm, through private discussions with the external auditors and management, that no restrictions are being placed on the scope of the external auditors' work;
7. Review the appropriateness of management's representation letter transmitted to the external auditors;
8. Receipt of certifications from the CEO and CFO;

9. Review with management the adequacy of annual and quarterly financial statements and disclosure in the management discussion and analysis and press release and recommend approval to the Board:
   a) obtain satisfactory answers from management following the review of the annual and quarterly financial statements and management discussion and analysis and press release;
   b) the qualitative judgments of the external auditors about the appropriateness, not just the acceptability, of accounting principles and financial disclosure practices used or proposed to be adopted by the Corporation and, particularly, their views about alternate accounting treatments and their effects on the financial results;
   c) the methods used to account for significant unusual transactions;
   d) the effect of significant accounting policies in controversial or emerging areas for which there is a lack of authoritative guidance or consensus;
   e) management's process for formulating sensitive accounting estimates and the reasonableness of these estimates;
   f) significant recorded and unrecorded audit adjustments;
   g) any material accounting issues among management and the external auditors;
   h) other matters required to be communicated to the Committee by the external auditors under generally accepted auditing standards;
   i) management's acknowledgement of its responsibility towards the financial statements;
   j) significant legal, compliance or regulatory matters that may have a material effect on the financial statements or the business of the organization (including material notices to, or inquiries received from, governmental agencies); and
   k) receive the report from the Reserves Committee over the appropriateness of reported reserves and resources.

Oversight of financial reporting process, internal controls, the continuous disclosure and certification process and compliance with regulatory requirements

10. Establishment of the Corporation's Whistleblower Policy for the submission, receipt, retention and treatment of complaints and concerns regarding accounting and auditing matters, and review any developments and responses on reports received thereunder;
11. Review the adequacy and effectiveness of the financial reporting system and internal control policies and procedures with the external auditors and management. Ensure that the Corporation complies with all new regulations in this regard;
12. Review with management the Corporation's internal controls, and evaluate whether the Corporation is operating in accordance with prescribed policies and procedures;
13. Review with management and the external auditors any reportable condition and material weaknesses affecting internal controls;
14. Review the management disclosure and oversight Committee's CEO and CFO certification processes to ensure compliance with U.S. and Canadian requirements.
15. Receive periodic reports from the external auditors and management to assess the impact of significant accounting or financial reporting developments proposed by the CICA, the AICPA, the Financial Accounting Standards Board, the SEC, the relevant Canadian securities commissions, stock exchanges or other regulatory body, or any other significant accounting or financial reporting related matters that may have a bearing on the Corporation;
16. Review annually the report of the external auditor on the Corporation's internal controls over financial reporting describing any material issues raised by the most recent reviews of internal controls and management information systems or by any inquiry or investigation by governmental or professional authorities and any recommendations made and steps taken to deal with any such issues;

Review of Business Risks

17. Review with management the process followed to do the Corporation's risk assessment and the policies to monitor, mitigate and report such business risks;

Other Matters

18. Review of appointment or dismissal of senior financial executives;
19. Conduct or authorize investigations into any matters within the Committee's scope of responsibilities, including retaining outside counsel or other consultants or experts for this purpose;
20. Review the disclosure made in the Annual Report, Annual Information Form, Form 40-F and the Information Circular regarding the Audit & Risk Management Committee;
21. Establish and maintain a free and open means of communication between the Board, the Committee, the external auditors, and management;
22. Perform such additional activities, and consider such other matters, within the scope of its responsibilities, as the Committee or the Board deems necessary or appropriate; and
23. Once a year, the Committee reviews the adequacy of its Charter and brings to the attention of the Board required changes, if any, for approval. The Committee is also reviewed annually by the Corporate Governance and Nominating Committee, which reports its findings to the Board.

While the Committee has the duties and responsibilities set forth in this Charter, the Committee is not responsible for planning or conducting the audit or for determining whether the Corporation's financial statements are complete and accurate and are in accordance with generally accepted accounting principles. Similarly, it is not the responsibility of the Committee to resolve disagreements, if any, between management and the external auditors. While it is acknowledged that the Committee is not legally obliged to ensure that the Corporation complies with all laws and regulations, the spirit and intent of this Charter is that the Committee shall take reasonable steps to encourage the Corporation to act in full compliance therewith.

Enerplus Corporation

The Dome Tower
3000, 333 - 7th Avenue S.W.
Calgary, Alberta, Canada
T2P 2Z1
Telephone: 403.298.2200
Toll free: 1.800.319.6462
Fax: 403.298.2211
www.enerplus.com