ANNUAL INFORMATION FORM

For the year ended December 31, 2011

March 9, 2012

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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, 2011, the Corporation's $1.0 billion 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 pursuant to a plan of arrangement under the ABCA;

"**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, *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;

"**Haas**" means Haas Petroleum Engineering Services, Inc., independent petroleum consultants;

"**Haas Report**" means the independent engineering evaluation of the Corporation's oil, NGLs, natural gas and shale gas reserves and contingent resources in the Marcellus Properties prepared by Haas effective December 31, 2011, utilizing commodity price forecasts of McDaniel (for internal consistency in Enerplus' reserves reporting) as of January 1, 2012;

"**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;

"**Marcellus Carry Amount**" has the meaning assigned thereto under "*General Development of the Business – Developments in the Past Three Years – Developments in 2009 – Acquisition of Interests in the Marcellus Shale Gas Play*";

"**Marcellus JDA**" means the Joint Development Agreement dated September 1, 2009 among Enerplus USA and the vendors of the interests acquired by Enerplus in the Marcellus shale gas resource play on September 1, 2009;

"**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 western United States prepared by McDaniel effective December 31, 2011, utilizing commodity price forecasts of McDaniel as of January 1, 2012;

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

"**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, 2011, the US$413.2 million principal amount and $40 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 shareholder rights plan agreement between the Corporation and Computershare Trust Company of Canada, as rights agent, dated effective January 1, 2011;

"**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;

"**Trust Units**" means the former trust units of the Fund, each of which represented an equal undivided beneficial interest in the Fund and which were exchanged on a one-for-one basis for Common Shares pursuant to the Conversion;

"**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
Bcf/day	billion cubic feet per day
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
McfGE[(1)]	one thousand cubic feet of natural gas equivalent
McfGE/day	one thousand cubic feet of natural gas equivalent per day
MMbbls	one million barrels
MMBOE[(1)]	one million barrels of oil equivalent
MMbtu	one million British Thermal Units
MMcf	one million cubic feet
MMcf/day	one million cubic feet per day
MMcfGE/day	one million cubic feet of natural gas equivalent per day
NGLs	natural gas liquids
NYMEX	the New York Mercantile Exchange
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) Enerplus 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 McfGEs, MMcfGEs and 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 30, 2011, the exchange rate for one Canadian dollar, expressed in U.S. dollars and based upon the noon buying rate of the Bank of Canada, was US$0.9833.

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 Reports on Reserves Data by McDaniel attached hereto as Appendix A, the Report on Reserves Data by Haas attached as Appendix B and the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix C. The effective date for the Statement of Reserves Data and Other Oil and Gas Information contained in this Annual Information Form is December 31, 2011 and the preparation date for such information is March 9, 2012.

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 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" 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.

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 now generally requires that reserve 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 reserve estimates based upon future or other prices. The Corporation has also provided certain supplemental information in this Annual Information Form (presented as "constant prices": see "*– Description of Price and Cost Assumptions*" below) in accordance with the SEC's pricing requirements. As a consequence of the foregoing, Enerplus' reserve 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, 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 McfGEs, MMcfGEs and BcfGEs. BOEs, MBOEs, MMBOEs, McfGEs, MMcfGEs 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 "contingent resources" which relate to the Corporation's interests in its Tight Oil, Marcellus Shale Gas and Crude Oil Waterflood play types.

"**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.

The contingent resource 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 resource 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 – Play Types – Marcellus Shale Gas*", "*Business of the Corporation – Play Types – Tight Oil*", "*Business of the Corporation – Play Types – Crude Oil Waterflood*" and "*Risk Factors – The Corporation's actual reserves and resources will vary from its reserve and resource 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:

"**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. See "*– Disclosure of Reserves and Production Information*" above.

"**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 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).

"**Constant prices and costs**" means, unless expressly noted otherwise, prices and costs used in an estimate that are the arithmetic average of the first-day-of-the-month price of the applicable commodity for each of the twelve months in 2011, held constant throughout the estimated lives of the properties to which the estimate applies.

Presentation of Financial Information

The financial information included or referred to in this Annual Information Form has been prepared in accordance with IFRS for financial periods beginning on January 1, 2011 including comparative amounts for the respective periods in 2010 and an opening balance sheet at January 1, 2010. IFRS differs in some significant respects from U.S. GAAP and therefore this financial information may not be comparable to the financial information of U.S. companies. A description of the impact of the Corporation's transition to IFRS is included in Note 18 to the Corporation's audited consolidated financial statements for the year ended December 31, 2011, which are available 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 by the Corporation with the SEC together with this Annual Information Form, and on the Corporation's website at www.enerplus.com. The SEC does not require the Corporation to reconcile its financial statements prepared in accordance with IFRS to U.S. GAAP.

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, natural gas and shale gas production levels;
- commodity prices, foreign currency exchange rates and interest rates;
- capital expenditure programs, drilling programs, development plans and other future expenditures, including the planned allocation of capital expenditures among the Corporation's play types, the timing of capital expenditures 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 reflect several material factors and expectations and assumptions made by the Corporation including, without limitation, that: 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; 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; there will be sufficient availability of services and labour to conduct the Corporation's operations as planned; and the Corporation's commodity price and other cost assumptions will generally be accurate. 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 these 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 in market prices for oil, NGLs, natural gas and shale 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 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, 2011, 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. 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. See "*General Development of the Business – Developments in the Past Three Years – Developments in 2010 – Conversion from an Income Trust to a 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.

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".

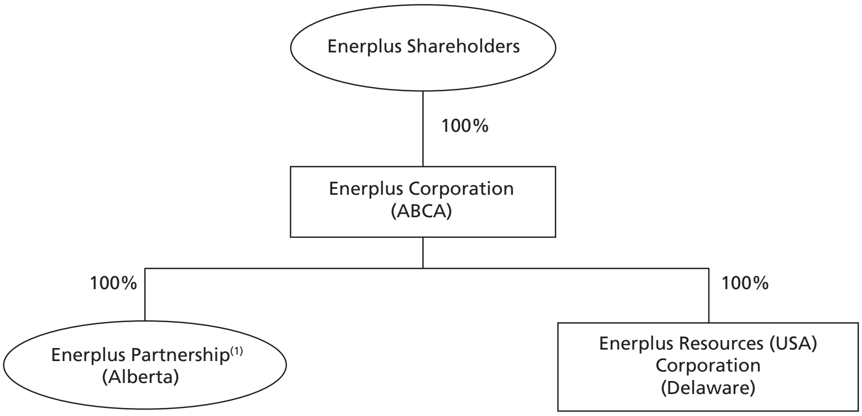
MATERIAL SUBSIDIARIES

As of December 31, 2011, the Corporation's material subsidiaries were Enerplus Partnership and Enerplus USA.

Enerplus Partnership is a general partnership organized under the laws of Alberta and Enerplus USA is a corporation organized under the laws of Delaware. All of the issued and outstanding securities of each of the Partnership and Enerplus USA are directly and indirectly owned by the Corporation.

ORGANIZATIONAL STRUCTURE

The simplified organizational structure of Enerplus Corporation and its material subsidiaries as of December 31, 2011 is set forth below.



Note:

(1) All of the partnership interests in Enerplus Partnership are owned by Enerplus Corporation and a wholly-owned subsidiary of Enerplus Corporation that is otherwise not material.

General Development of the Business

DEVELOPMENTS IN THE PAST THREE YEARS

Developments in 2009

Acquisition of Interests in the Marcellus Shale Gas Play

On September 1, 2009, Enerplus (through the Fund's indirect wholly-owned subsidiary, Enerplus USA) acquired an average 21.5% working interest in approximately 116,000 net acres within the Marcellus shale natural gas play in the northeastern United States, the majority of which was located in Pennsylvania with certain interests in Maryland and West Virginia. Total consideration for the acquisition was approximately US$411.0 million. The transaction had an effective date of May 1, 2009. The acquisition was structured as two components, with one portion of the interests conveyed to Enerplus upon closing on September 1, 2009 and the remaining portion conveyed to Enerplus pursuant to the Marcellus JDA, as described in further detail below.

At the September 1, 2009 closing, Enerplus acquired an approximate 8.6% working interest in the subject Marcellus properties for cash consideration of US$164.4 million, which was paid at closing. Enerplus and the vendors of the interests also entered into the Marcellus JDA on the closing date of the transaction, under which Enerplus acquired an additional approximate 12.9% working interest in the subject Marcellus properties. Under the terms of the Marcellus JDA, the consideration of US$246.6 million (the "**Marcellus Carry Amount**") for these additional working interests is paid over time as a "carry" and represents 50% of the vendors' share of the future well drilling and completion costs on the subject Marcellus properties until the Marcellus Carry Amount has been fully expended. As of December 31, 2011, the remaining Marcellus Carry Amount was approximately US$36 million. Based on existing future drilling and completion plans, Enerplus anticipates the remaining Marcellus Carry Amount will be spent in 2012.

For a description of Enerplus' Marcellus shale gas interests, see "*Business of the Corporation – Play Types – Marcellus Shale Gas*".

Additional Strategic Acquisitions and Dispositions

In 2009, Enerplus acquired additional Bakken land interests in North Dakota and southeast Saskatchewan for a purchase price of approximately $55.0 million. Enerplus also disposed of $104.3 million of assets, almost all of which related to the sale of a non-core oil property in western Canada, with production of approximately 200 BOE/day.

Developments in 2010

Acquisition of Additional Bakken Properties in North Dakota

On October 15, 2010, Enerplus acquired an additional 46,500 net acres (72 sections) of land in the Fort Berthold area of Dunn and McKenzie counties in North Dakota. These lands were directly adjacent to Enerplus' existing land holdings in this area and are prospective for light crude oil in the Bakken and Three Forks formations. The purchase price was US$468.7 million (before closing adjustments) and was funded through Enerplus' Bank Credit Facility. Throughout 2010, Enerplus completed additional acquisitions in the Fort Berthold area, resulting in total acquisitions in the Fort Berthold area in 2010 (including the October 15, 2010 acquisition described above) of 58,921 net acres, including production of 1,900 BOE/day, for an aggregate purchase price of $588.0 million. For a description of Enerplus' Bakken interests, see "*Business of the Corporation – Play Types – Tight Oil*".

Acquisition of Additional Operated Marcellus Properties

On August 23, 2010, Enerplus purchased 58,500 net acres of undeveloped land in the Marcellus shale natural gas play in West Virginia and Maryland. The acreage was predominantly located in Preston County in West Virginia and Garrett County in Maryland and created a new, concentrated, operated land position with an average 90% working interest. These lands were in emerging areas with limited existing development. In total, Enerplus spent $169.3 million on property acquisitions in the Marcellus shale gas play in 2010 (in addition to expenditures of $92.3 million contributed towards the Marcellus Carry Amount), acquiring the two key operated areas described above and acquiring a total of approximately 75,317 net acres of undeveloped land, most of which was operated by Enerplus.

Sale of Non-Core Conventional Assets and Additional Acquisitions

In 2010, Enerplus executed on its strategy to sell non-core conventional assets in order to improve its focus and operational efficiency. During the year, Enerplus sold approximately 10,400 BOE/day of production for approximately $465.2 million. The proceeds from these sales were used to retire outstanding debt under the Bank Credit Facility.

In addition to the acquisitions described above, in 2010 Enerplus purchased approximately 104,500 net acres of prospective land contiguous to its existing holdings in the Freda Lake, Neptune and Oungre areas of the Saskatchewan Bakken play for $118.7 million. Enerplus also acquired approximately 36,100 net acres of undeveloped land in the British Columbia Deep Basin for $25.9 million.

Sale of Kirby Oil Sands Lease

On October 1, 2010, Enerplus sold 100% of its Kirby oil sands lease for proceeds of $404.8 million. Enerplus acquired a 100% working interest in the Kirby lease in 2007 for $203.1 million and since that time had invested an additional $58 million in the Kirby lease to further delineate and identify the bitumen resource on the lease. Proceeds from the sale were used to retire outstanding debt under the Bank Credit Facility.

Developments in 2011

Conversion from an Income Trust to a Corporation

As a result of the implementation of the legislation governing the tax on mutual fund trusts in June 2007 that subjected certain types of publicly traded mutual fund trusts, such as the Fund, to tax at rates comparable to the combined federal and provincial corporate tax rates beginning in the 2011 tax year, on January 1, 2011 Enerplus completed the Conversion pursuant to a plan of arrangement under the ABCA. The Conversion, together with a related internal corporate reorganization, resulted in the business and structure of Enerplus being reorganized from an income trust, with the parent entity being the Fund, into a corporate structure, with the parent entity being the Corporation. As part of the Conversion and related reorganization transactions, unitholders of the Fund exchanged their trust units for Common Shares of the Corporation on a one-for-one basis, the Fund was dissolved, all of the outstanding Trust Units were cancelled and the Corporation continued as the successor issuer to the Fund. The business, directors and management of the Corporation immediately following completion of the Conversion were the same as the business of the Fund and the directors and management of the Fund (through its administrator, EnerMark Inc.) immediately before completion of the Conversion. As a result of the Conversion, the Corporation became a reporting issuer in each of the provinces and territories of Canada.

Sale of Non-Core Marcellus Acreage

In 2011, the Corporation sold approximately 45% of its total Marcellus acreage, consisting of non-core and primarily non-operated acreage in Pennsylvania, Maryland and West Virginia, for approximately $568 million, capturing a pre-tax gain of $272 million on the sale. The Corporation retained approximately 110,000 net acres in the Marcellus play, of which 60% is operated. The sale included approximately 5.4 MMcfGE/day of natural gas production and approximately 23.4 BcfGE of proved plus probable reserves. Proceeds from the sale were used to reduce the amount drawn under the Bank Credit Facility.

RECENT DEVELOPMENTS

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. The Corporation intends to subsequently utilize such proceeds to fund its capital expenditure program in 2012.

Business of the Corporation

OVERVIEW

In 2011, following completion of the Conversion, the Corporation continued to move from an income model to a growth and income-oriented model. Enerplus continued to focus on delivering operational results, repositioning its asset base and adding key leadership and technical skills. The Corporation believes that it has made significant progress with respect to these strategies and that it is well positioned for success as the new growth plays begin to contribute to its results during 2012.

Enerplus has realigned its asset base to include not only mature income-oriented assets but also early stage, growth-oriented assets. The Corporation believes that it has accumulated a meaningful portfolio of prospects, including interests in the Marcellus shale gas play in the United States, the Bakken play primarily in North Dakota and Montana, as well as the Deep Basin region of Alberta and British Columbia. The Corporation believes that it is well-positioned to provide organic growth potential in the future and that a greater concentration of assets will allow it to focus its activities on a fewer number of high impact properties to create the greatest value for its investors. The Corporation's acquisition and development activities are generally focused on "resource plays", which are typically large and aerially extensive accumulations of discovered oil and natural gas with limited geological risk. Resource plays typically require many wells to develop the play over time. Resource plays generally exhibit lower production decline rates over the long term and a longer reserve life.

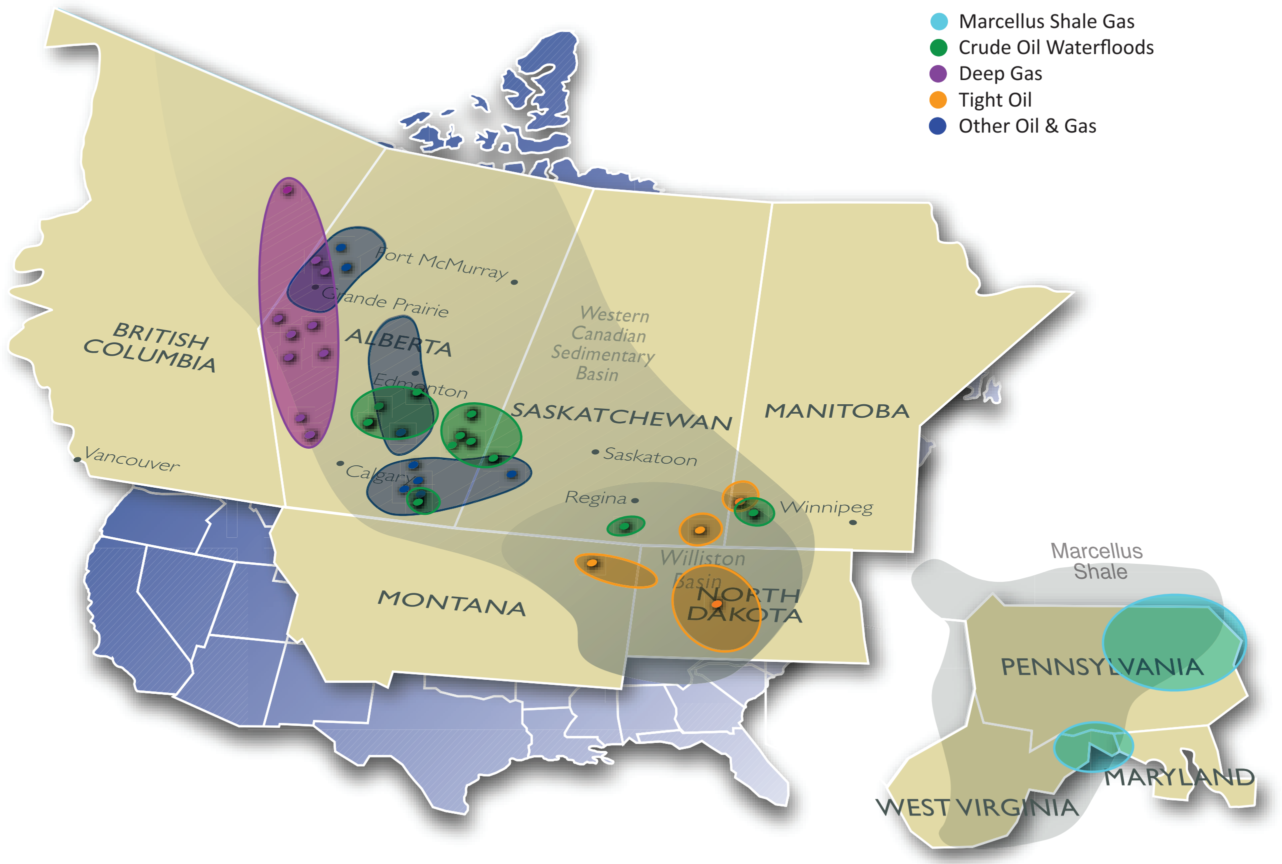
The Corporation has categorized its key assets and operations into four play types, which include: (i) Tight Oil primarily in Montana and North Dakota; (ii) Marcellus Shale Gas in the northeastern United States; (iii) Deep Gas in northwestern Alberta and northeastern British Columbia; and (iv) Crude Oil Waterfloods throughout western Canada. Additionally, the Corporation has interests in other oil and natural gas properties throughout western Canada, including shallow gas in southeastern and central Alberta and southwestern Saskatchewan. Each of these play types and property interests is described in detail under "– *Play Types*" below.

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, 2011, (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 reserve volumes represent gross reserves using forecast prices and costs. See "*Presentation of Oil and Gas Reserves, Resources and Production Information*".

The Corporation's oil and natural gas property interests are located primarily in western Canada in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba, and in the United States primarily in the states of Montana, North Dakota, Maryland, Pennsylvania, West Virginia and Wyoming. The Corporation's major producing properties have related field production facilities and infrastructure to accommodate the Corporation's production. Production volumes for the year ended December 31, 2011 from the Corporation's properties consisted of approximately 44% crude oil and NGLs and 56% natural gas, on a BOE basis. The Corporation's 2011 average daily production was 75,332 BOE/day, comprised of 30,181 bbls/day of crude oil, 3,306 bbls/day of NGLs and 251.1 MMcf/day of natural gas, a decrease of approximately 9.4% compared to 2010 average daily production of 83,139 BOE/day, comprised of 31,135 bbls/day of crude oil, 3,889 bbls/day of NGLs and 288.7 MMcf/day of natural gas. The decline in average daily production in 2011 is largely attributable to the sale throughout 2010 of approximately 10,400 BOE/day of non-core production, a significant amount of which occurred late in 2010, and the sale of approximately 1,100 BOE/day of natural gas production from the Corporation's Marcellus interests in 2011. The Corporation exited 2011 with average daily production of approximately 82,000 BOE/day. Approximately 70% of the Corporation's 2011 production was operated by the Corporation and the remaining 30% was operated by industry partners.

As at December 31, 2011, the oil and natural gas property interests held by the Corporation were estimated to contain proved plus probable gross reserves of 130,746 Mbbls of light and medium crude oil, 39,376 Mbbls of heavy crude oil, 13,360 Mbbls of NGLs, 639,471 MMcf of natural gas and 153,543 MMcf of shale gas, for a total of 315,651 MBOE. The Corporation's proved reserves represented approximately 69% of total proved plus probable reserves, and approximately 58% of the Corporation's proved plus probable reserves were weighted to crude oil and NGLs. See "*Oil and Natural Gas Reserves*".

SUMMARY OF PRINCIPAL PRODUCTION LOCATIONS



The following table outlines the Corporation's gross reserves as at December 31, 2011 and its average daily production in 2011 for the Corporation's play types and its other oil and natural gas properties.

Play Type	Proved Reserves	Probable Reserves	Proved Plus Probable Reserves	Average Daily Production
	(MMBOE)	(MMBOE)	(MMBOE)	(BOE/day)
Crude Oil				
Tight Oil	48.3	35.4	83.7	13,616
Crude Oil Waterfloods	69.1	20.7	89.8	15,127
Other Oil	13.1	4.5	17.6	4,661
Total Crude Oil	130.6	60.6	191.1	33,404
	(BcfGE)	(BcfGE)	(BcfGE)	(McfGE/day)
Natural Gas				
Marcellus Shale Gas	92.7	60.9	153.5	20,524
Deep Gas	195.5	93.0	288.5	82,983
Other Natural Gas	229.0	76.1	305.1	148,057
Total Natural Gas	517.1	229.9	747.1	251,564
Total	**216.7 MMBOE**	**98.9 MMBOE**	**315.6 MMBOE**	**75,332 BOE/day**

During the year ended December 31, 2011, on a BOE basis, approximately 53% of the Corporation's production was derived from Alberta, 16% from Saskatchewan, 10% from Montana, 7% from each of North Dakota and British Columbia, 4% from Pennsylvania, 2% from Manitoba and minimal amounts from other jurisdictions such as Utah, Wyoming and West Virginia. The following table describes the average daily production from the Corporation's principal producing properties and their primary play type during the year ended December 31, 2011.

2011 Average Daily Production from Principal Properties

		Product				
		Crude Oil				
Property	**Primary Play Type**	**Heavy**	**Light and Medium**	**NGLs**	**Natural Gas**	**Total**
		(bbls/day)	(bbls/day)	(bbls/day)	(Mcf/day)	(BOE/day)
Sleeping Giant, Montana, U.S.A.	Tight Oil	–	5,760	–	8,969	7,255
Shackleton, Saskatchewan	Other Oil and Gas	–	–	–	34,942	5,824
Fort Berthold, North Dakota, U.S.A.	Tight Oil	–	5,242	39	187	5,312
Tommy Lakes, British Columbia	Deep Gas	–	14	483	23,045	4,338
Marcellus, Eastern U.S.A.	Marcellus Shale Gas	–	–	59	20,170	3,421
Medicine Hat Glauconitic "C" Unit, Alberta	Crude Oil Waterflood	2,606	–	–	237	2,646
Bantry, Alberta	Other Oil and Gas	–	3	1	14,659	2,447
Brooks North, Alberta	Other Oil and Gas	923	–	38	7,368	2,189
Pembina 5 Way, Alberta	Crude Oil Waterflood	–	1,700	108	2,190	2,172
Giltedge, Alberta	Crude Oil Waterflood	1,942	–	–	130	1,963
Pine Creek, Alberta	Deep Gas	–	21	411	8,994	1,931
Freda Lake, Saskatchewan	Crude Oil Waterflood	–	1,766	–	–	1,766
Verger, Alberta	Other Oil and Gas	–	–	–	9,704	1,617
Brooks South, Alberta	Crude Oil Waterflood	1,302	–	5	1,131	1,496
Joarcam, Alberta	Crude Oil Waterflood	–	878	52	3,313	1,482
Elmworth, Alberta	Deep Gas	–	–	256	6,774	1,385
Ansell, Alberta	Deep Gas	–	–	56	7,555	1,315
Hanna Garden, Alberta	Other Oil and Gas	–	–	1	7,852	1,310
Burnt Timber, Alberta	Deep Gas	–	–	7	6,692	1,123
Virden, Manitoba	Crude Oil Waterflood	–	1,021	–	–	1,021
Medicine Hat South, Alberta	Other Oil and Gas	–	–	–	5,961	994
Other	N/A	1,454	5,549	1,790	81,195	22,325
TOTAL		8,227	21,954	3,306	251,068	75,332

CAPITAL EXPENDITURES AND COSTS INCURRED

In 2011, the Corporation invested approximately $865.7 million through its capital program, which was approximately 61% higher than the $536.4 million spent on its capital program in 2010. The Corporation increased its spending on its key growth areas with the majority directed towards its Tight Oil ($375 million), Crude Oil Waterflood ($164 million) and Marcellus Shale Gas ($210 million) properties. The foregoing does not include approximately $255.2 million of expenditures made on property and land acquisitions in 2011, which amount includes $109.6 million expended on the Marcellus Carry Amount in 2011.

In the financial year ended December 31, 2011, the Corporation made the following expenditures in the categories noted, as prescribed by NI 51-101:

	Property Acquisition Costs		Exploration	Development
	Proved	Unproved	Costs	Costs
	($ in millions)			
Canada	2.1	110.4	37.2	288.7
United States	–	33.2[1]	72.6	467.2
Total	2.1	143.6	109.8	755.9

Note:

(1) Excludes $109.6 million spent on the Marcellus Carry Amount in 2011, as the entire Marcellus Carry Amount was included in 2009 information.

The Corporation expects its 2012 exploration and development capital spending to be approximately $800 million, with over 70% projected to be invested in oil and liquids-rich natural gas projects. The Corporation expects to focus approximately 85% of its 2012 development capital on its Tight Oil, Crude Oil Waterflood and Marcellus Shale Gas play types. The Corporation expects to invest approximately $350 million of capital on its Tight Oil play, with approximately $300 million targeted for its Fort Berthold property, $150 million in its Crude Oil Waterflood portfolio and $80 million in the Deep Gas play. With continued low natural gas prices, the majority of the Corporation's natural gas spending is planned for its Marcellus interests, where the Corporation expects to spend approximately $190 million on drilling to further delineate the resource and retain the Corporation's lease positions largely on non-operated interests. The Corporation intends to finance its 2012 capital expenditure program through a combination of internally-generated cash flow, debt and equity financing (including the net proceeds of the February 2012 equity offering of approximately $331 million) and proceeds from its dividend reinvestment plan. The Corporation will review its 2012 capital investment plans regularly throughout the year in the context of prevailing economic conditions and potential acquisitions, and make adjustments as it deems necessary. Over and above its 2012 capital spending program, the Corporation plans to invest an additional $40 million towards the acquisition of new undeveloped land. The Corporation intends to finance this additional $40 million through the sale of non-core properties with limited production, and has completed the sale of approximately 35% of this amount as of the date hereof.

For additional information regarding the Corporation's planned 2012 development capital expenditures for each of its play types and its other oil and natural gas assets, see "– *Play Types*" 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, 2011, 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	119	45.6	13	2.7	39	25.8	3	2.5
Natural gas wells	22	7.4	3	3.0	164	17.0	–	–
Service wells	38	1.8	–	–	1	1.0	–	–
Dry and abandoned wells	1	0.5	–	–	–	–	–	–
Total	180	55.3	16	5.7	204	43.8	3	2.5

For a description of the Corporation's planned 2012 development plans and the anticipated sources of funding those plans, see "– *Capital Expenditures and Costs Incurred*" above and "– *Play Types*" below.

OIL AND NATURAL GAS WELLS AND UNPROVED PROPERTIES

The following table summarizes, as at December 31, 2011, 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
Alberta	1,672	857.5	6,449	3,388.9	646	302.3	810	263.4	752,331	331,135
Saskatchewan	2,336	475.7	2,490	2,266.2	628	131.3	212	184.0	519,849	431,009
British Columbia	0	0.0	235	156.1	0	0.0	53	19.0	114,349	76,021
Manitoba	477	259.2	0	0.0	123	73.7	0	0.0	17,625	7,682
Ontario	0	0.0	0	0.0	0	0.0	0	0.0	33,187	0
Montana	251	144.5	1	0.7	1	0.7	0	0.0	3,745	3,745
North Dakota	80	46.2	4	1.2	9	5.1	0	0.0	47,962	46,017
Utah	2	1.8	0	0.0	0	0.0	0	0.0	6,740	6,414
Colorado	0	0.0	0	0.0	0	0.0	0	0.0	46,199	42,567
Pennsylvania	0	0.0	118	12.5	0	0.0	211	17.2	208,918	46,967
West Virginia	0	0.0	0	0.0	0	0.0	4	3.0	42,957	42,957
Maryland	0	0.0	0	0.0	0	0.0	0	0.0	17,060	17,060
Total	4,818	1,784.9	9,297	5,825.6	1,407	513.1	1,290	4,86.6	1,810,922	1,051,574

The Corporation expects its rights to explore, develop and exploit on approximately 100,000 net acres of unproved properties to expire prior to December 31, 2012 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.

PLAY TYPES

Outlined below is a description of each of the Corporation's four play types and its other oil and natural gas properties.

Tight Oil

Overview

The Corporation's Tight Oil play includes properties located primarily in Montana and North Dakota, including an approximate 70% average working interest in the Sleeping Giant Bakken oil field in Richland County, Montana and an approximate 90% average working interest at the Fort Berthold property in Dunn and McKenzie counties in North Dakota, which were two of the three largest producing properties of the Corporation in 2011. The Corporation's Tight Oil properties are predominantly operated by the Corporation. Production from the Corporation's North Dakota and Montana properties is primarily from the Middle Bakken dolomite formation at a depth of approximately 10,000 feet and consists of light sweet crude oil (42° API) and some associated natural gas. The Corporation's Tight Oil play produced approximately 13,616 BOE/day in 2011, representing approximately 18% of the Corporation's 2011 average daily production on a BOE basis, and exited 2011 with production of 16,203 BOE/day. In particular, production from the Sleeping Giant field averaged 7,255 BOE/day in 2011 and production from the Fort Berthold property increased from 4,000 BOE/day at the start of 2011 to approximately 9,000 BOE/day to exit 2011. The Corporation expects to grow production from the Fort Berthold region to 20,000 to 25,000 BOE/day over the next two to three years. The Corporation added approximately 36 MMBOE of proved plus probable reserves in the Fort Berthold field during 2011, including converting 30 MMBOE of year-end 2010 contingent resources to reserves, and as of December 31, 2011 approximately 27% of the Corporation's proved plus probable reserves were attributable to the Tight Oil properties. The Corporation also holds over 75,000 net acres of land that is prospective for the Bakken and the Three Forks formations in certain areas.

The Corporation spent approximately $375 million of capital on its Tight Oil properties in 2011, including approximately $290 million at its Fort Berthold property, representing the single largest capital investment in the Corporation's portfolio. In 2011, the Corporation drilled 34 net horizontal wells at its Tight Oil properties, including 25 net operated wells drilled at the Fort Berthold property (consisting of 18 short lateral wells and 7 long lateral wells) with approximately 21 net operated wells brought on stream during 2011.

The Corporation expects to spend approximately $350 million, representing approximately 40% of its 2012 capital budget, on its Tight Oil properties, approximately $300 million of which has been targeted for the Fort Berthold area. The Corporation plans to drill 27 net horizontal wells at Fort Berthold with at least 90% of these wells planned as long lateral horizontal wells with three to four drilling rigs working in the play during 2012. The primary target will be the Bakken formation, however the Corporation also plans to drill a number of wells targeting the Three Forks formation underlying the Bakken to continue to evaluate the potential and future prospectivity of this zone.

Contingent Resource Estimate

An evaluation of the Corporation's interests in the Bakken and Three Forks formations at the Fort Berthold, North Dakota property conducted internally by the Corporation and audited by McDaniel has attributed a "best estimate" of 49 MMBOE of contingent resources attributable to these formations, effective as of December 31, 2011. As described above, the Corporation converted 30 MMBOE of the estimated 60 MMBOE of Bakken contingent resources as at December 31, 2010 into reserves during the year, leaving approximately 30 MMBOE of contingent resources attributable to the Bakken formation and adding 19 MMBOE of contingent resources attributable to the Three Forks formation at December 31, 2011. These contingent resources represent 78 net future drilling locations over and above the 60 gross (53 net) booked drilling locations in the Corporation's booked proved plus probable reserves based primarily upon a drilling density of two wells per drilling spacing unit in both the Bakken and Three Forks formations. Both the Bakken and Three Forks contingent resources are economic using established technologies and under current commodity prices. Given the drilling density to date, the Corporation assumed a land utilization of 90% for the Bakken and only 35% for the Three Forks given the limited well control at this time. Enerplus has approximately 115 net sections of land in the Fort Berthold region with less than 50 wells currently on production. 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 establish economic productivity in the development 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 early performance of producing wells being above forecast. A significant negative factor related to the estimate is the limited performance history in the immediate area of the contingent resource. There are a number of inherent risks and contingencies associated with the development of the acquired 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 provisions 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.

Marcellus Shale Gas

Overview

Enerplus made its initial strategic investment in the Marcellus shale gas fairway in 2009, gaining entry into one of the largest shale gas plays in North America. In 2010, Enerplus continued to add to its Marcellus interests through the acquisition of operated interests in Pennsylvania, West Virginia and Maryland. Through four transactions completed in 2010 totalling $169.3 million, Enerplus acquired 75,317 net acres of land, almost all of which were operated interests. In 2011, the Corporation sold approximately 45% of its total Marcellus acreage, consisting of non-core and primarily non-operated acreage in Pennsylvania, Maryland and West Virginia, for approximately $568 million. For additional information, see "*General Development of the Business — Developments in the Past Three Years*".

At December 31, 2011, the Corporation had an approximate 35% average working interest in approximately 350,000 gross acres (approximately 110,000 net acres) in the Marcellus play, 60% of which is operated. The Corporation's operated position in this play consists of approximately 67,000 net acres located in West Virginia and Maryland, and its non-operated position includes approximately 44,000 net acres concentrated in the northeastern area of Pennsylvania. The majority of the non-operated leases allow extensions of the primary term, with a payment, for an additional five years. Including lease extensions, the Corporation's operated acreage has average tenures of approximately five years. The Corporation's Marcellus properties produced an average of 20,524 McfGE/day in 2011, with a 2011 exit production rate of 25,213 McfGE/day. The Marcellus properties were estimated to contain 153.5 BcfGE of proved plus probable reserves as at December 31, 2011, an increase of 64% from 2010 year-end proved plus probable reserves, adjusted for the 2011 dispositions.

The Corporation's Marcellus activities were focused on delineation drilling, lease retention, production and reserves development in 2011. Approximately $210 million was invested on delineation and development drilling activities (including $109.6 million expended on the Marcellus Carry Amount and $36 million on properties that were subsequently divested), with approximately 75% of this amount invested with the Corporation's partners in its non-operated operations in the northeastern region of Pennsylvania. The Corporation participated in the drilling of a total of 16 net wells (12 non-operated and four operated) during 2011. However, due to delays in pipeline infrastructure, only 5.3 net non-operated wells were brought on stream in 2011. As of February 2012, the Corporation had 13 net producing wells (120 gross wells) in the region, and 16 net wells (246 gross wells) waiting on completions or tie-in.

The Corporation plans to incur approximately $190 million of capital expenditures on its Marcellus properties in 2012, plus an additional US$36 million to be expended as the final portion of the Marcellus Carry Amount. Approximately 80% of the capital expenditures are planned to be spent on the Corporation's non-operated interests in the northeast area of Pennsylvania. With the current low natural gas price environment, the Corporation plans to invest with its partners to retain its interests in this valuable acreage. Well costs in this region are currently averaging $7 million to $8 million per well, and the Corporation plans to direct approximately $30 million to $40 million to drill appraisal wells on its operated leases in Pennsylvania where it is focused on demonstrating the potential in these areas and retaining its lease interests. In total, the Corporation expects to participate in drilling approximately 19 net wells in the Marcellus play in 2012, with approximately 18 net wells on stream in 2012. The Corporation expects its total Marcellus production to grow from 25 MMcf/day at the end of 2011 to close to 70 MMcf/day as it exits 2012.

As of December 31, 2011, the Corporation's remaining commitment under the Marcellus Carry Amount was approximately US$36 million. Under the terms of the Marcellus JDA, which only applies to the initial lands in which the Corporation acquired an interest in September 2009, until the full Marcellus Carry Amount has been spent by the Corporation, the operators of the subject properties have the sole right to propose the drilling and development of wells on these properties and the Corporation is required to participate in those operations (subject to certain exceptions, including limitations on wells drilled subsequent to an initial well being drilled in an area or when the operator has failed to conduct sufficient drilling activities as set out in the Marcellus JDA), and the operations on the subject properties will be conducted in accordance with a mutually agreed-upon development plan. Following the Corporation's expenditure of the required Marcellus Carry Amount, either of the Corporation or the operator can propose well drilling and development plans and the other party may elect whether or not it will participate in such drilling and development. If a party elects not to participate, the provisions of the operating agreement with respect to the applicable area will govern the rights and remedies between the parties.

The Marcellus JDA also includes area of mutual interest provisions with the vendors of the Corporation's interests in the Marcellus properties acquired in 2009 that will provide the Corporation the opportunity to partner with the vendors in any follow-on acquisitions or swaps in the Marcellus region. These provisions will provide the Corporation with the opportunity to jointly acquire more land under the current ownership structure, as well as the potential to increase its working interest ownership on new lands and operate in certain new areas.

The Corporation has entered into long-term agreements for the gathering, dehydration, processing and compression 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 Resource Estimate

Haas has also 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 natural gas contingent resources of approximately 2.3 Tcf at December 31, 2011. This estimate is essentially unchanged from the December 31, 2010 best estimate of contingent resources associated with the Marcellus properties (net of contingent resources sold in 2011) despite the booking of significant reserves previously classified as contingent resources. These contingent resources are economic based on the forecast price and cost assumptions used for the Corporation's year-end 2011 reserves evaluations. This estimate assumes a land utilization rate of 83.4% and that the average well would produce approximately 5.3 Bcf.

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 establish economic productivity in 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 provisions 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*".

Crude Oil Waterfloods

Overview

The Corporation's Crude Oil Waterflood assets are a core part of its business contributing low decline, stable production and cash flow to support investment in the Corporation's new growth plays. This portfolio includes a variety of properties producing from formations such as the Cardium, Viking, Ratcliffe, Lloydminster and Glauconitic that offer new drilling opportunities, optimization and enhanced oil recovery potential. Through horizontal drilling technology and reservoir depletion analysis, the Corporation has identified new opportunities in a number of these mature fields that it believes will help offset declines and, in some areas, provide a modest level of growth. 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 reserve recovery even further.

In 2011, the Corporation's five largest Crude Oil Waterflood producing properties were Medicine Hat, Pembina 5 Way, Giltedge, Freda Lake and Brooks South, all of which are located in Alberta with the exception of Freda Lake, which is in Saskatchewan. The Corporation operated approximately 94% of its 2011 Crude Oil Waterflood production. All of the Corporation's major waterflood areas have associated crude oil production installations for emulsion treating and injection or water disposal. The Corporation's Crude Oil Waterflood properties produced an average of 15,127 BOE/day in 2011, representing approximately 20% of the Corporation's production for the year, and exited 2011 producing 16,760 BOE/day. This play was attributed 90 MMBOE of proved plus probable reserves as at December 31, 2011, representing approximately 28% of the Corporation's proved plus probable reserves.

The Corporation's activities in 2011 in this play were focused on enhancing the value of these assets through both drilling activity and enhanced oil recovery techniques. The Corporation invested approximately $164 million on these properties in 2011 with approximately 60% directed to drilling and completions and the remainder on plant and facility enhancements to support future activities. The Corporation drilled 34.1 net wells on these properties in 2011 (essentially all of which were horizontal wells), with the majority of such drilling in the Ratcliffe, Viking and Cardium plays. During 2011, the Corporation advanced work on its two enhanced oil recovery projects at Giltedge and Medicine Hat. To date, production results from the Giltedge project area are better than anticipated and the Corporation expects to expand the polymer flood by adding three injection wells in 2012. The Corporation's activities at Medicine Hat included facilities improvements in preparation for polymer injection in the first quarter of 2012. In 2011, the Corporation replaced 100% of production from these properties, adding approximately 5.6 MMBOE of proved plus probable reserves, including the conversion to reserves of 800,000 BOE of contingent resources associated with its polymer project at Giltedge and 3.4 MMBOE of contingent resources associated with its incremental oil recovery projects.

The Corporation plans to spend approximately $150 million on its Crude Oil Waterflood assets in 2012, to maintain production volumes. The Corporation plans to direct $85 million to drilling, completions and injector conversion activities, $58 million on plants, facilities and maintenance, and $7 million on its enhanced oil recovery projects at Giltedge and Medicine Hat. With a low estimated base decline rate of approximately 12%, the Corporation believes these properties provide a complement to its newer growth properties that have higher initial decline rates.

Contingent Resource Estimate

Enerplus has conducted an internal evaluation of the contingent resources associated with only a portion of its Crude Oil Waterflood projects, which has resulted in a "best estimate" of 56 MMBOE being classified as contingent resources effective as of December 31, 2011. These contingent resources are economic based on the price and cost assumptions used in the Corporation's 2011 year-end reserves evaluations. Incremental oil recovery from seven existing waterfloods through optimization work accounts for approximately 22 MMBOE of the total. Approximately 34 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 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 for other of the Corporation's waterflood properties, these have not been thoroughly evaluated and are not classified as 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". 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. 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 provisions 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*".

Deep Gas

The Corporation's Deep Gas play, which includes the Corporation's liquids-rich natural gas prospects in Alberta and British Columbia as well as other deep natural gas properties, produced an average of 13,830 BOE/day (exiting 2011 at 16,900 BOE/day) in 2011, representing 18% of the Corporation's 2011 average daily production, and were attributed 48 MMBOE of proved plus probable reserves as at December 31, 2011, representing approximately 15% of the Corporation's reserves. The Corporation's largest producing properties in this play in 2011 were its Tommy Lakes property in northern British Columbia, and Pine Creek, Elmworth, Ansell and Burnt Timber, all of which are located in Alberta. This play includes multi-zone tight natural gas plays such as the Mannville, Nikannassin, Montney, Bluesky, Nordegg and Halfway zones. In addition, the Corporation has accumulated approximately 165,000 net acres of undeveloped land which it believes is prospective for liquids-rich natural gas targeting the Montney, Stacked Mannville and Duvernay formations.

Capital spending on the Corporation's Deep Gas properties in 2011 was approximately $91 million. The Corporation drilled 8.3 net wells on these properties in 2011. In 2011, the Corporation continued to delineate its Stacked Mannville position in the Ansell/Minehead/Hanlan areas of

Alberta, drilling three Wilrich wells and one Bluesky operated well. Results from the Corporation's 2011 drilling activities were positive as production from these properties grew from 13,800 BOE/day to 16,900 BOE/day as the Corporation exited 2011. The Corporation added to its Montney formation land position throughout 2011, acquiring approximately 17,000 net acres in the Cameron area, taking its total Montney land position to approximately 33,000 net acres. The Corporation drilled its first vertical Montney delineation well at the end of 2011 and expects to complete this well in early 2012. The Corporation also owns approximately 70,000 net acres of undeveloped land targeting the liquids-rich Duvernay formation in the Willesden Green region of central Alberta and plans to drill its first vertical Duvernay delineation wells in 2012.

As a result of continued weak natural gas prices, the Corporation plans to take a measured approach to spending in this area in 2012. The Corporation expects to invest approximately $80 million on both its operated and non-operated leases in the area. The Corporation's operated activities will target the Stacked Mannville formation and delineate its Montney and Duvernay acreage positions.

Other Oil and Natural Gas Assets

In addition to the play types outlined above, the Corporation also owns other oil and natural gas assets across western Canada. These assets include a diversified portfolio of both operated and non-operated crude oil and natural gas projects and consist of various reservoir types. The principal properties in this category include crude oil producing properties in Brooks North and Chinchaga in Alberta, the Hanlan-Robb natural gas property in Alberta and shallow natural gas interests at Shackleton in southwest Saskatchewan and at Bantry, Verger, Hanna Garden and Medicine Hat South in Alberta. Production from these other conventional oil and natural gas properties averaged approximately 29,337 BOE/day in 2011, representing approximately 39% of the Corporation's average daily production. These properties also accounted for 68 MMBOE of proved plus probable reserves at December 31, 2011, representing approximately 22% of the Corporation's estimated total proved plus probable reserves.

Development capital expended on those properties in 2011 was reduced to approximately $27 million, given low natural gas prices impacting certain of these properties and the Corporation's desire to concentrate its capital spending and efforts in its core areas. The Corporation plans to spend approximately $30 million of capital on its other oil and gas properties in 2012.

EQUITY INVESTMENTS

In 2005, Enerplus formed a joint venture with Laricina, a private oil sands company focused on development in the Athabasca oil sands fairway. As part of this joint venture, Enerplus swapped a 1% working interest in the Joslyn oil sands lease for approximately 20% equity value in Laricina. In February 2012 the Corporation sold land interests to Laricina in exchange for additional common shares of Laricina. After this transaction, the Corporation owned approximately five million common shares of Laricina, representing approximately 8% of the total outstanding shares of Laricina.

The Corporation also has minor equity interests in several other resource focused entities with an estimated fair value of approximately $24 million at December 31, 2011.

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 2011 and for the entire year, separately for production in Canada and the United States, and in total.

	Year Ended December 31, 2011				
Country and Product Type	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Canada					
Light and medium oil (bbls/day)	11,239	10,734	10,424	11,204	**10,898**
Heavy oil (bbls/day)	7,956	8,200	8,222	8,522	**8,227**
Total crude oil (bbls/day)	19,195	18,934	18,646	19,726	**19,125**
Natural gas liquids (bbls/day)	3,098	3,344	3,065	3,201	**3,177**
Total liquids (bbls/day)	22,293	22,278	21,711	22,927	**22,302**
Natural gas (Mcf/day)	217,373	225,158	215,826	218,176	**219,129**
Total Canada (BOE/day)	58,522	59,805	57,682	59,290	**58,824**
United States					
Light and medium oil (bbls/day)	11,143	10,396	10,691	11,989	**11,056**
Natural gas liquids (bbls/day)	134	98	230	55	**129**
Total liquids (bbls/day)	11,277	10,494	10,921	12,044	**11,185**
Natural gas (Mcf/day)	34,107	30,507	27,849	35,324	**31,939**
Total United States (BOE/day)	16,961	15,578	15,563	17,931	**16,508**
Total					
Light and medium oil (bbls/day)	22,382	21,130	21,115	23,193	**21,954**
Heavy oil (bbls/day)	7,956	8,200	8,222	8,522	**8,227**
Total crude oil (bbls/day)	30,338	29,330	29,337	31,715	**30,181**
Natural gas liquids (bbls/day)	3,232	3,442	3,295	3,256	**3,306**
Total liquids (bbls/day)	33,570	32,772	32,632	34,971	**33,487**
Natural gas (Mcf/day)	251,480	255,665	243,675	253,500	**251,068**
Total (BOE/day)	75,483	75,383	73,245	77,221	**75,332**

QUARTERLY NETBACK HISTORY

The following tables set forth the Corporation's average netbacks received for each fiscal quarter in 2011 and for the entire year, separately for production in Canada and the United States. 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, 2011				
Light and Medium Crude Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Canada					
Sales price[1]	$ 82.60	$ 97.03	$ 85.20	$ 90.21	**$ 88.74**
Royalties	(13.97)	(15.61)	(13.21)	(14.99)	**(14.46)**
Production costs[2]	(20.26)	(24.62)	(26.96)	(27.71)	**(24.88)**
Netback	$ 48.37	$ 56.80	$ 45.03	$ 47.51	**$ 49.40**
United States					
Sales price[1]	$ 81.89	$ 94.79	$ 77.45	$ 89.84	**$ 86.01**
Royalties[3]	(21.62)	(22.67)	(21.30)	(23.65)	**(22.34)**
Production costs[2]	(4.89)	(6.46)	(8.45)	(7.78)	**(6.92)**
Netback	$ 55.38	$ 65.66	$ 47.70	$ 58.41	**$ 56.75**
Total Enerplus					
Sales price[1]	$ 82.25	$ 95.93	$ 81.28	$ 90.02	**$ 87.36**
Royalties[3]	(17.78)	(19.08)	(17.31)	(19.46)	**(18.43)**
Production costs[2]	(12.61)	(15.69)	(17.59)	(17.41)	**(15.83)**
Netback	$ 51.86	$ 61.16	$ 46.38	$ 53.15	**$ 53.10**

	Year Ended December 31, 2011				
Heavy Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Canada/Total					
Sales price[1]	$ 64.85	$ 78.01	$ 68.04	$ 80.86	**$ 73.10**
Royalties[3]	(13.16)	(15.90)	(13.68)	(17.16)	**(15.02)**
Production costs[2]	(9.87)	(11.15)	(11.25)	(15.19)	**(11.93)**
Netback	$ 41.82	$ 50.96	$ 43.11	$ 48.51	**$ 46.15**

Natural Gas Liquids ($ per bbl)	Year Ended December 31, 2011 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
Canada					
Sales price(1)	$ 61.28	$ 66.37	$ 65.77	$ 68.83	**$ 65.63**
Royalties	(17.25)	(18.04)	(18.01)	(22.24)	**(18.91)**
Production costs(2)	–	–	–	–	**–**
Netback	$ 44.03	$ 48.33	$ 47.76	$ 46.59	**$ 46.72**
United States					
Sales price(1)	$ 37.24	$ 60.41	$ 54.36	$ 38.31	**$ 49.40**
Royalties(3)	(2.12)	(10.02)	(10.26)	(6.81)	**(7.76)**
Production costs(2)	–	–	–	–	**–**
Netback	$ 35.12	$ 50.39	$ 44.10	$ 31.50	**$ 41.64**
Total					
Sales price(1)	$ 60.29	$ 66.20	$ 64.98	$ 68.32	**$ 64.99**
Royalties(3)	(16.62)	(17.81)	(17.47)	(21.98)	**(18.47)**
Production costs(2)	–	–	–	–	**–**
Netback	$ 43.67	$ 48.39	$ 47.51	$ 46.34	**$ 46.52**

Natural Gas ($ per Mcf)	Year Ended December 31, 2011 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
Canada					
Sales price(1)	$ 3.69	$ 3.69	$ 3.65	$ 3.13	**$ 3.54**
Royalties	(0.27)	(0.24)	(0.23)	(0.18)	**(0.23)**
Production costs(2)	(1.18)	(1.30)	(1.47)	(1.58)	**(1.38)**
Netback	$ 2.24	$ 2.15	$ 1.95	$ 1.37	**$ 1.93**
United States					
Sales price(1)	$ 5.28	$ 5.12	$ 4.32	$ 5.11	**$ 4.98**
Royalties(3)	(1.02)	(1.15)	(0.86)	(0.97)	**(1.00)**
Production costs(2)	(0.52)	(0.89)	(0.69)	(0.71)	**(0.70)**
Netback	$ 3.74	$ 3.08	$ 2.77	$ 3.43	**$ 3.28**
Total					
Sales price(1)	$ 3.91	$ 3.86	$ 3.73	$ 3.41	**$ 3.72**
Royalties(3)	(0.37)	(0.35)	(0.30)	(0.29)	**(0.33)**
Production costs(2)	(1.09)	(1.25)	(1.38)	(1.46)	**(1.29)**
Netback	$ 2.45	$ 2.26	$ 2.05	$ 1.66	**$ 2.10**

Total ($ per BOE)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
	Year Ended December 31, 2011				
Canada					
Sales price(1)	$ 41.76	$ 45.89	$ 42.32	$ 44.15	**$ 43.55**
Royalties	(6.40)	(6.89)	(6.17)	(7.17)	**(6.66)**
Production costs(2)	(9.60)	(10.83)	(11.97)	(13.22)	**(11.42)**
Netback	$ 25.76	$ 28.17	$ 24.18	$ 23.76	**$ 25.47**
United States					
Sales price(1)	$ 64.72	$ 73.65	$ 61.74	$ 70.25	**$ 67.63**
Royalties(3)	(16.27)	(17.43)	(16.33)	(17.73)	**(16.96)**
Production costs(2)	(4.25)	(6.05)	(7.04)	(6.60)	**(5.98)**
Netback	$ 44.20	$ 50.17	$ 38.37	$ 45.92	**$ 44.69**
Total Enerplus					
Sales price(1)	$ 46.92	$ 51.62	$ 46.44	$ 50.29	**$ 48.85**
Royalties(3)	(8.62)	(9.07)	(8.33)	(9.62)	**(8.92)**
Production costs(2)	(8.40)	(9.84)	(10.92)	(11.69)	**(10.23)**
Netback	$ 29.90	$ 32.71	$ 27.19	$ 28.98	**$ 29.70**

Notes:

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

(2) 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.

(3) Includes U.S. state production taxes.

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's Energy Resources Conservation Board, together with other operating assumptions. The Corporation expects all of its net wells to incur these costs. Enerplus anticipates the total amount of such costs, net of estimated salvage value for such equipment, to be approximately $645 million on an undiscounted basis and $124 million discounted at 10% in accordance with NI 51-101. The calculations of future net revenue under *"Oil and Natural Gas Reserves"* in this Annual Information Form exclude approximately $309 million on an undiscounted basis and $30 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 $64 million on an undiscounted basis and $56 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 generally does not expect to be pay material cash taxes in Canada until after 2015 as it estimates it has sufficient tax pools to offset taxable income prior to that time. The Corporation expects to pay cash taxes of approximately 5% of U.S. cash flow in 2012 mainly related to 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 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. However, the Corporation emphasizes that it is difficult to give guidance on future taxability as it operates within an industry that constantly changes given acquisitions, divestments, capital spending, overall commodity prices and governing tax laws. See "*Risk Factors – Changes in tax and other laws may adversely affect Enerplus and its shareholders*."

For additional information, see Notes 2(m) and 12 to the Corporation's audited consolidated financial statements for the year ended December 31, 2011 and the information under the heading "*Taxes*" in the Corporation's MD&A for the year ended December 31, 2011.

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 on 30 day continuously renewing contracts for crude oil and yearly contracts for NGLs whose terms fluctuate with monthly spot market prices. The Corporation received an average price (net of transportation costs but before the effects of commodity derivative instruments) of $87.36/bbl for its light and medium crude oil, $73.10/bbl for its heavy crude oil and $64.99/bbl for its NGLs for the year ended December 31, 2011, compared to $72.91/bbl for its light and medium crude oil, $63.17/bbl for its heavy crude oil and $51.41/bbl for its NGLs for the year ended December 31, 2010. The Corporation has contracted transportation for 1,000 bbls/day of its Bakken oil production until May 2016, and an additional 7,500 bbls/day commencing January 1, 2013 for five years. The Corporation has also entered into a two year commitment to deliver crude oil to a purchaser with rail capacity out of North Dakota, consisting of 6,000 bbls/day commencing February 1, 2012 and decreasing to 4,000 bbls/day commencing February 1, 2013.

Natural Gas

In marketing its natural gas production the Corporation tries to achieve a mix of contracts and customers. Within its sales portfolio of aggregator, downstream and spot natural gas sales, the Corporation sold approximately 82.5% of its natural gas split evenly between the daily and monthly AECO market indices and 17.5% against monthly U.S.-based indices.

The Corporation's percentage of 2011 revenues attributable to natural gas (net of transportation costs but before the effects of commodity derivative instruments) was 26% compared to 33% in 2010. The average price received by the Corporation (net of transportation costs but before the effects of commodity derivative instruments) for its natural gas in 2011 was $3.72/Mcf compared to $4.05/Mcf for the year ended December 31, 2010.

The Corporation has contracted to transport approximately 200 MMcf/day of natural gas in Canada with contracts that range anywhere from one month to five years.

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 15 to the Corporation's audited consolidated financial statements for the year ended December 31, 2011 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, 2011, 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. McDaniel, an independent petroleum consulting firm based in Calgary, Alberta, has evaluated properties which comprise approximately 78% 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 substantially all of the Corporation's reserves located in the western United States. The Corporation has evaluated the balance of these 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.

Haas, independent petroleum consultants based in Dallas, Texas, has evaluated all of the Corporation's reserves attributable to the Marcellus properties located in the northeastern United States. For consistency in the Corporation's reserves reporting, Haas used McDaniel's January 1, 2012 forecast prices and inflation rates to prepare their reports. The Corporation used McDaniel's forecast exchange rates set forth below to convert U.S. dollar amounts in the Haas Report to Canadian dollar amounts for presentation in this Annual Information Form.

The following sections and tables summarize, as at December 31, 2011, 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, 2010 to December 31, 2011, 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 both before and after 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 the differing costs of service applied by various purchasers. 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 reserve 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, 2011, using both forecast and constant 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 6,268 MBOE 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.

Summary of Oil and Gas Reserves
As of December 31, 2011

Forecast Prices and Costs

	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	41,006	36,815	25,546	20,962	7,114	4,939	389,282	346,501	–	–	138,547	120,466
United States	24,811	20,347	–	–	603	513	26,259	25,456	43,738	30,593	37,080	30,202
Total	65,817	57,162	25,546	20,962	7,717	5,452	415,541	371,957	43,738	30,593	175,627	150,668
Proved Developed Non-Producing												
Canada	1,298	1,125	376	326	94	72	8,039	6,815	–	–	3,107	2,659
United States	1,108	909	–	–	22	18	930	773	16,317	13,271	4,005	3,266
Total	2,406	2,034	376	326	116	90	8,969	7,588	16,317	13,271	7,112	5,925
Proved Undeveloped												
Canada	3,574	3,050	3,368	2,695	471	363	27,761	24,319	–	–	12,040	10,161
United States	14,771	11,681	–	–	753	615	6,015	6,879	32,627	26,474	21,964	17,855
Total	18,345	14,731	3,368	2,695	1,224	978	33,776	31,198	32,627	26,474	34,004	28,016
Total Proved												
Canada	45,878	40,990	29,290	23,983	7,679	5,374	425,082	377,635	–	–	153,694	133,286
United States	40,690	32,937	–	–	1,378	1,146	33,204	33,108	92,682	70,338	63,049	51,323
Total	86,568	73,927	29,290	23,983	9,057	6,520	458,286	410,743	92,682	70,338	216,743	184,609
Probable												
Canada	13,396	11,596	10,086	7,995	2,925	2,111	163,844	143,824	–	–	53,714	45,673
United States	30,782	24,601	–	–	1,378	1,168	17,341	21,652	60,861	48,183	45,194	37,408
Total	44,178	36,197	10,086	7,995	4,303	3,279	181,185	165,476	60,861	48,183	98,908	83,081
Total Proved Plus Probable												
Canada	59,274	52,586	39,376	31,978	10,604	7,485	588,926	521,459	–	–	207,408	178,959
United States	71,472	57,538	–	–	2,756	2,314	50,545	54,760	153,543	118,521	108,243	88,731
Total	130,746	110,124	39,376	31,978	13,360	9,799	639,471	576,219	153,543	118,521	315,651	267,690

Summary of Net Present Value of Future Net Revenue Attributable to Oil and Gas Reserves as of December 31, 2011

Forecast Prices and Costs

	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	4,193	2,855	2,199	1,810	1,552	3,604	2,532	1,992	1,666	1,446	$18.25
United States	1,765	1,225	956	796	689	1,190	833	654	547	476	$31.65
Total	5,958	4,080	3,155	2,606	2,241	4,794	3,365	2,646	2,213	1,922	$20.94
Proved Developed Non-Producing											
Canada	128	98	80	68	59	95	73	60	52	45	$30.09
United States	104	76	61	50	42	67	49	40	34	29	$18.68
Total	232	174	141	118	101	162	122	100	86	74	$23.80
Proved Undeveloped											
Canada	335	211	139	93	61	248	151	95	58	34	$13.68
United States	671	412	269	181	122	394	237	151	98	63	$15.07
Total	1,006	623	408	274	183	642	388	246	156	97	$14.56
Total Proved											
Canada	4,656	3,164	2,418	1,971	1,672	3,947	2,756	2,147	1,776	1,525	$18.14
United States	2,540	1,713	1,286	1,027	853	1,651	1,119	845	679	568	$25.06
Total	7,196	4,877	3,704	2,998	2,525	5,598	3,875	2,992	2,455	2,093	$20.06
Probable											
Canada	2,094	999	603	413	304	1,550	738	444	302	221	$13.20
United States	2,355	1,378	947	712	566	1,402	815	558	418	330	$25.32
Total	4,449	2,377	1,550	1,125	870	2,952	1,553	1,002	720	551	$18.66
Total Proved Plus Probable											
Canada	6,750	4,163	3,021	2,384	1,976	5,497	3,494	2,591	2,078	1,746	$16.88
United States	4,895	3,091	2,233	1,739	1,419	3,053	1,934	1,403	1,097	898	$25.17
Total	11,645	7,254	5,254	4,123	3,395	8,550	5,428	3,994	3,175	2,644	$19.63

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.

Summary of Oil and Gas Reserves
As of December 31, 2011

Constant Prices and Costs

	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	41,176	37,642	25,636	21,479	6,784	4,700	353,348	318,891	–	–	132,487	116,969
United States	24,652	20,222	–	–	594	506	26,201	25,410	43,144	30,113	36,804	29,982
Total	65,828	57,864	25,636	21,479	7,378	5,206	379,549	344,301	43,144	30,113	169,291	146,951
Proved Developed Non-Producing												
Canada	1,298	1,132	376	332	89	68	7,588	6,629	–	–	3,028	2,636
United States	1,104	905	–	–	22	17	930	771	15,713	12,777	3,899	3,180
Total	2,402	2,037	376	332	111	85	8,518	7,400	15,713	12,777	6,927	5,816
Proved Undeveloped												
Canada	3,574	3,062	3,311	2,734	192	156	11,482	10,034	–	–	8,990	7,625
United States	14,698	11,624	–	–	749	612	5,988	6,859	31,818	25,850	21,748	17,687
Total	18,272	14,686	3,311	2,734	941	768	17,470	16,893	31,818	25,850	30,738	25,312
Total Proved												
Canada	46,048	41,836	29,323	24,545	7,065	4,924	372,418	335,554	–	–	144,505	127,230
United States	40,454	32,751	–	–	1,365	1,135	33,119	33,040	90,675	68,740	62,451	50,849
Total	86,502	74,587	29,323	24,545	8,430	6,059	405,537	368,594	90,675	68,740	206,956	178,079
Probable												
Canada	13,467	11,930	10,107	8,374	2,467	1,737	131,306	119,434	–	–	47,925	41,947
United States	30,759	24,583	–	–	1,377	1,167	17,334	21,647	60,338	47,816	45,082	37,328
Total	44,226	36,513	10,107	8,374	3,844	2,904	148,640	141,081	60,338	47,816	93,007	79,275
Total Proved Plus Probable												
Canada	59,515	53,766	39,430	32,919	9,532	6,661	503,724	454,988	–	–	192,430	169,177
United States	71,213	57,334	–	–	2,742	2,302	50,453	54,687	151,013	116,556	107,533	88,177
Total	130,728	111,100	39,430	32,919	12,274	8,963	554,177	509,675	151,013	116,556	299,963	257,354

Summary of Net Present Value of Future Net Revenue
Attributable to Oil and Gas Reserves
as of December 31, 2011

Constant Prices and Costs

	NET PRESENT VALUE OF FUTURE NET REVENUE DISCOUNTED AT (%/YEAR)										
	Before Deducting Income Taxes					After Deducting Income Taxes					
RESERVES CATEGORY	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**Unit Value(1)**
					(in $ millions)						($/BOE)
Proved Developed Producing											
Canada	3,561	2,496	1,959	1,635	1,417	3,137	2,265	1,814	1,536	1,345	$ 16.75
United States	1,452	1,074	866	735	644	1,006	744	601	511	448	$ 28.88
Total	5,013	3,570	2,825	2,370	2,061	4,143	3,009	2,415	2,047	1,793	$ 19.22
Proved Developed Non-Producing											
Canada	112	88	72	63	55	83	65	55	48	44	$ 27.31
United States	78	62	50	42	36	50	40	34	29	26	$ 15.72
Total	190	150	122	105	91	133	105	89	77	70	$ 20.98
Proved Undeveloped											
Canada	279	180	123	85	59	207	130	85	56	35	$ 16.13
United States	511	327	218	147	98	301	188	122	79	50	$ 12.33
Total	790	507	341	232	157	508	318	207	135	85	$ 13.47
Total Proved											
Canada	3,952	2,764	2,154	1,783	1,531	3,427	2,460	1,954	1,640	1,424	$ 16.93
United States	2,041	1,463	1,134	924	778	1,357	972	757	619	524	$ 22.30
Total	5,993	4,227	3,288	2,707	2,309	4,784	3,432	2,711	2,259	1,948	$ 18.46
Probable											
Canada	1,466	746	473	336	256	1,084	552	349	248	188	$ 11.28
United States	1,774	1,129	811	626	506	1,061	670	478	367	296	$ 21.73
Total	3,240	1,875	1,284	962	762	2,145	1,222	827	615	484	$ 16.20
Total Proved Plus Probable											
Canada	5,418	3,510	2,627	2,119	1,787	4,511	3,012	2,303	1,888	1,612	$ 15.53
United States	3,815	2,592	1,945	1,550	1,284	2,418	1,642	1,235	986	820	$ 22.06
Total	9,233	6,102	4,572	3,669	3,071	6,929	4,654	3,538	2,874	2,432	$ 17.77

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, 2012 (and utilized by Haas and by Enerplus 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	Propanes	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)
2012	97.50	99.00	74.00	91.00	3.50	3.75	54.60	76.20	106.00	2.0	0.975
2013	97.50	99.00	74.00	91.00	4.20	4.50	56.40	79.80	104.10	2.0	0.975
2014	100.00	101.50	75.90	93.30	4.70	5.05	58.90	81.80	104.60	2.0	0.975
2015	100.80	102.30	76.50	94.10	5.10	5.50	60.40	82.40	105.50	2.0	0.975
2016	101.70	103.20	77.10	94.90	5.55	5.95	62.00	83.20	106.40	2.0	0.975
Thereafter	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)		0.975

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40^0 API/0.5% sulphur.
(2) Edmonton Light Sweet 40^0 API/0.3% sulphur.
(3) Heavy Crude Oil 12^0 API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).
(4) Midale Cromer Crude Oil 29^0 API/2.0% sulphur.
(5) Escalation varies until 2020 and is approximately 2% per year thereafter.

In 2011, the Corporation received a weighted average price (net of transportation costs but before hedging) of $73.10/bbl for heavy crude oil, $87.36/bbl for light and medium crude oil, $64.99/bbl for NGLs and $3.72/Mcf for natural gas.

CONSTANT PRICES AND COSTS

The constant price and cost case is based upon an unweighted arithmetic average of the first-day-of-the-month price for the applicable commodity for each of the twelve months preceding the company's fiscal year-end as at December 31, 2011, held constant throughout the estimated lives of the properties to which the estimate applies, and assumes the continuance of operating costs projected for 2012 and the continuance of current laws and regulations. Product prices have not been escalated nor have operating and capital costs been increased on an inflationary basis. The future net revenue to be received from the production of the reserves was based on the following constant prices determined as at December 31, 2011 and the following 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	Propanes	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)
2012 Constant	96.19	97.30	68.84	90.30	3.75	4.18	56.83	77.17	106.30	–	0.9845

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40^0 API/0.5% sulphur.
(2) Edmonton Light Sweet 40^0 API/0.3% sulphur.
(3) Heavy Crude Oil 12^0 API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).
(4) Midale Cromer Crude Oil 29^0 API/2.0% sulphur.

UNDISCOUNTED FUTURE NET REVENUE BY RESERVES CATEGORY

The undiscounted total future net revenue by reserves category as of December 31, 2011, 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	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
				(in $ millions)				
Proved Reserves								
Canada	10,625	1,546	3,729	402	292	4,656	709	3,947
United States	5,219	1,404	791	470	14	2,540	889	1,651
Total	15,844	2,950	4,520	872	306	7,196	1,598	5,598
Proved Plus Probable Reserves								
Canada	14,793	2,220	4,969	536	318	6,750	1,253	5,497
United States	9,343	2,529	1,169	734	17	4,895	1,842	3,053
Total	24,136	4,749	6,138	1,270	335	11,645	3,095	8,550

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, 2011, 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)	1,237	$30.33/bbl
	Heavy Oil(1)	713	$29.75/bbl
	Natural Gas(2)	468	$1.37/Mcf
	Shale Gas(4)	n/a	n/a
	Total	2,418	
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	1,500	$28.66/bbl
	Heavy Oil(1)	860	$26.89/bbl
	Natural Gas(2)	661	$1.39/Mcf
	Shale Gas(4)	n/a	n/a
	Total	3,021	
United States			
Proved Reserves	Light and Medium Crude Oil(1)	1,136	$34.50/bbl
	Heavy Oil(1)	n/a	n/a
	Natural Gas(2)	21	$3.68/Mcf
	Shale Gas(4)	129	$1.83/Mcf
	Total	1,286	
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	1,994	$34.66/bbl
	Heavy Oil(1)	n/a	n/a
	Natural Gas(2)	40	$3.04/Mcf
	Shale Gas(4)	199	$1.68/Mcf
	Total	2,233	
Total			
Proved Reserves	Light and Medium Crude Oil(1)	2,373	$32.19/bbl
	Heavy Oil(1)	713	$29.75/bbl
	Natural Gas(2)	489	$1.40/Mcf
	Shale Gas(4)	129	$1.83/Mcf
	Total	3,704	
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	3,494	$31.80/bbl
	Heavy Oil(1)	860	$26.89/bbl
	Natural Gas(2)	701	$1.43/Mcf
	Shale Gas(4)	199	$1.68/Mcf
	Total	5,254	

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 production estimated for 2012 in preparing the estimates of gross proved reserves and gross probable reserves is set forth below. Canadian production has been estimated by McDaniel and U.S. production has been aggregated from estimates provided by McDaniel and Haas. Actual 2012 production (including from the Fort Berthold property in the separate table below) may vary from the estimates provided by McDaniel and Haas as the Corporation's actual development programs, timing and priorities may differ from the forecast of development by McDaniel and Haas. Columns may not add due to rounding.

	Gross Proved Reserves							
	Canada				United States			
Product Type	**Estimated 2012 Aggregate Production**		**Estimated 2012 Average Daily Production**		**Estimated 2012 Aggregate Production**		**Estimated 2012 Average Daily Production**	
Crude Oil								
Light and Medium Crude Oil	4,156	Mbbls	11,356	bbls/day	5,975	Mbbls	16,325	bbls/day
Heavy Oil	3,041	Mbbls	8,307	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	7,197	Mbbls	19,663	bbls/day	5,975	Mbbls	16,325	bbls/day
Natural Gas Liquids	1,011	Mbbls	2,762	bbls/day	224	Mbbls	615	bbls/day
Total Liquids	8,208	Mbbls	22,425	bbls/day	6,200	Mbbls	16,940	bbls/day
Natural Gas	66,529	MMcf	181,774	Mcf/day	4,249	MMcf	11,610	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	12,104	MMcf	33,070	Mcf/day
Total	19,296	MBOE	52,721	BOE/day	8,926	MBOE	24,387	BOE/day

	Gross Probable Reserves							
	Canada				United States			
Product Type	**Estimated 2012 Aggregate Production**		**Estimated 2012 Average Daily Production**		**Estimated 2012 Aggregate Production**		**Estimated 2012 Average Daily Production**	
Crude Oil								
Light and Medium Crude Oil	212	Mbbls	577	bbls/day	2,540	Mbbls	6,939	bbls/day
Heavy Oil	104	Mbbls	287	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	316	Mbbls	864	bbls/day	2,540	Mbbls	6,939	bbls/day
Natural Gas Liquids	53	Mbbls	145	bbls/day	126	Mbbls	344	bbls/day
Total Liquids	369	Mbbls	1,009	bbls/day	2,666	Mbbls	7,283	bbls/day
Natural Gas	3,543	MMcf	9,678	Mcf/day	1,059	MMcf	2,892	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	963	MMcf	2,632	Mcf/day
Total	960	MBOE	2,622	BOE/day	3,003	MBOE	8,204	BOE/day

The following table sets forth McDaniel's estimated 2012 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 2012 production.

	Estimated 2012 Production for Fort Berthold Property							
	Gross Proved Reserves				Gross Probable Reserves			
Product Type	**Estimated 2012 Aggregate Production**		**Estimated 2012 Average Daily Production**		**Estimated 2012 Aggregate Production**		**Estimated 2012 Average Daily Production**	
Crude Oil								
Light and Medium Crude Oil	4,100	Mbbls	11,201	bbls/day	2,325	Mbbls	6,352	bbls/day
Heavy Oil	–	Mbbls	–	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	4,100	Mbbls	11,201	bbls/day	2,325	Mbbls	6,352	bbls/day
Natural Gas Liquids	225	Mbbls	615	bbls/day	126	Mbbls	344	bbls/day
Total Liquids	4,325	Mbbls	11,817	bbls/day	2,451	Mbbls	6,696	bbls/day
Natural Gas	1,501	MMcf	4,101	Mcf/day	840	MMcf	2,295	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	–	MMcf	–	Mcf/day
Total	4,575	MBOE	12,501	BOE/day	2,591	MBOE	7,079	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 proceeds from the dividend reinvestment program of the Corporation, as well as through debt or the issuance of Common Shares where required. 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*" and "*Business of the Corporation – Exploration and Development Activities*".

	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)				
2012	168	160	189	180	333	317	472	451
2013	90	78	136	118	95	83	165	143
2014	55	44	96	76	14	11	33	27
2015	13	9	38	27	18	13	38	27
2016	8	6	8	6	9	6	23	17
Remainder	68	26	69	27	1	1	3	–
Total	402	323	536	434	470	431	734	665

RECONCILIATION OF RESERVES

Overview

The Corporation's total gross proved plus probable reserves at December 31, 2011 were approximately 315.7 MMBOE, up approximately 5% from year-end 2010. The Corporation's gross proved plus probable oil and NGLs reserves grew by approximately 14% to total 183.5 MMBOE and now represent approximately 58% of total proved plus probable gross reserves, up from 53% at year-end 2010. The Corporation replaced approximately 179% of its 2011 gross production through its exploration and development program, adding 48 MMBOE of proved plus probable reserves. Approximately 75% of the additions were oil and NGLs, representing the replacement of 300% the Corporation's 2011 oil and NGLs production. The largest amount of reserve additions were in the Corporation's Fort Berthold crude oil property in North Dakota. The Corporation sold 5.2 MMBOE of proved plus probable reserves in 2011, including 23 BcfGE associated with the disposition of certain Marcellus interests. After giving effect to these dispositions, the Corporation replaced approximately 160% of 2011 gross production volumes. As a result of the weak outlook for natural gas prices, approximately 33 BcfGE of natural gas reserves were removed from the Corporation's reserves at year-end. Total proved plus probable natural gas reserves declined by approximately 5% from year-end 2010.

Despite a 30% decrease in the forecast price for natural gas, the estimated net present value of future net revenues from the Corporation's reserves (discounted at 10%, before taxes) increased by almost 10% as a result of the increased weighting of light sweet crude oil reserves in its reserves portfolio.

The following tables reconcile the Corporation's gross oil and natural gas reserves from December 31, 2010 to December 31, 2011, 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, 2010	49,068	13,935	63,003	29,163	9,780	38,943	8,390	2,786	11,176
Acquisitions	125	34	159	–	–	–	–	–	–
Dispositions	(779)	(331)	(1,110)	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	3,107	1,266	4,373	1,081	1,049	2,130	324	173	497
Economic Factors	52	(13)	39	28	7	35	(133)	(140)	(273)
Technical Revisions	(1,783)	(1,495)	(3,278)	2,006	(750)	1,256	220	106	326
Production	(3,912)	–	(3,912)	(2,988)	–	(2,988)	(1,122)	–	(1,122)
December 31, 2011	45,878	13,396	59,274	29,290	10,086	39,376	7,679	2,925	10,604

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, 2010	497,545	170,393	667,938	–	–	–	169,546	54,899	224,445
Acquisitions	–	–	–	–	–	–	125	34	159
Dispositions	(689)	(226)	(915)	–	–	–	(894)	(368)	(1,262)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	20,371	10,234	30,605	–	–	–	7,907	4,194	12,101
Economic Factors	(16,059)	(10,294)	(26,353)	–	–	–	(2,730)	(1,861)	(4,591)
Technical Revisions	1,421	(6,263)	(4,842)	–	–	–	679	(3,184)	(2,505)
Production	(77,507)	–	(77,507)	–	–	–	(20,939)	–	(20,939)
December 31, 2011	425,082	163,844	588,926	–	–	–	153,694	53,714	207,408

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, 2010	30,622	16,181	46,803	–	–	–	33	59	92
Acquisitions	–	–	–	–	–	–	–	–	–
Dispositions	–	–	–	–	–	–	(11)	(60)	(71)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	12,236	17,319	29,555	–	–	–	668	937	1,605
Economic Factors	–	–	–	–	–	–	–	–	–
Technical Revisions	1,798	(2,718)	(920)	–	–	–	723	442	1,165
Production	(3,966)	–	(3,966)	–	–	–	(35)	–	(35)
December 31, 2011	40,690	30,782	71,472	–	–	–	1,378	1,378	2,756

(continued on next page)

(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, 2010	37,327	15,910	53,237	52,225	64,437	116,662	45,581	29,631	75,212
Acquisitions	–	–	–	–	–	–	–	–	–
Dispositions	–	–	–	(10,299)	(12,693)	(22,992)	(1,728)	(2,175)	(3,903)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	4,456	6,302	10,758	55,435	28,993	84,428	22,886	24,138	47,024
Economic Factors	–	–	–	(3,824)	(1,819)	(5,643)	(637)	(304)	(941)
Technical Revisions	(5,347)	(4,871)	(10,218)	6,507	(18,057)	(11,550)	2,714	(6,096)	(3,382)
Production	(3,232)	–	(3,232)	(7,362)	–	(7,362)	(5,767)	–	(5,767)
December 31, 2011	33,204	17,341	50,545	92,682	60,861	153,543	63,049	45,194	108,243

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, 2010	79,690	30,116	109,806	29,163	9,780	38,943	8,423	2,845	11,268
Acquisitions	125	34	159	–	–	–	–	–	–
Dispositions	(779)	(331)	(1,110)	–	–	–	(11)	(60)	(71)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	15,343	18,585	33,928	1,081	1,049	2,130	992	1,110	2,102
Economic Factors	52	(13)	39	28	7	35	(133)	(140)	(273)
Technical Revisions	15	(4,213)	(4,198)	2,006	(750)	1,256	943	548	1,491
Production	(7,878)	–	(7,878)	(2,988)	–	(2,988)	(1,157)	–	(1,157)
December 31, 2011	86,568	44,178	130,746	29,290	10,086	39,376	9,057	4,303	13,360

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, 2010	534,872	186,303	721,175	52,225	64,437	116,662	215,127	84,530	299,657
Acquisitions	–	–	–	–	–	–	125	34	159
Dispositions	(689)	(226)	(915)	(10,299)	(12,693)	(22,992)	(2,622)	(2,543)	(5,165)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	24,827	16,536	41,363	55,435	28,993	84,428	30,793	28,332	59,125
Economic Factors	(16,059)	(10,294)	(26,353)	(3,824)	(1,819)	(5,643)	(3,367)	(2,165)	(5,532)
Technical Revisions	(3,926)	(11,134)	(15,060)	6,507	(18,057)	(11,550)	3,393	(9,280)	(5,887)
Production	(80,739)	–	(80,739)	(7,362)	–	(7,362)	(26,706)	–	(26,706)
December 31, 2011	458,286	181,185	639,471	92,682	60,861	153,543	216,743	98,908	315,651

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)]	Heavy	Light and Medium	NGLs	Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
Aggregate prior to 2009	6,037	16,210	1,812	264,660	–	68,169
2009	812	2,133	17	4,198	4,587	4,426
2010	–	6,674	60	3,238	11,160	9,134
2011	885	10,397	572	8,629	25,817	17,595

Probable Undeveloped Reserves

	Crude Oil					
Year[(1)]	Heavy	Light & Medium	NGLs	Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
Aggregate prior to 2009	1,837	8,303	831	145,240	–	35,178
2009	779	527	52	6,065	14,463	4,779
2010	–	3,322	92	2,396	45,733	11,436
2011	127	15,178	871	11,515	21,135	21,618

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

A decrease in future commodity prices, and in particular natural gas 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 reserve and resource estimates, and those variations could be material*".

PROVED AND PROBABLE RESERVES NOT ON PRODUCTION

The Corporation has approximately 12.1 MMBOE of proved plus probable reserves which are capable of production but which, as of December 31, 2011, were not on production. These reserves have generally been non-producing for periods ranging from a few months to more than five years. In general, 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, or are related to reserves volumes which require the completion of infrastructure before production can begin.

Supplemental Operational Information

SAFETY AND SOCIAL RESPONSIBILITY

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 and promoting active and open collaboration with its stakeholders. Additionally, the Corporation actively participates in industry recognized programs that support its sustainable mindset, which expects continuous improvement.

The Corporation has a Health and Safety Policy, an Environment Policy and a Stakeholder Engagement Policy that articulate its commitment to safety and social responsibility ("**S&SR**"). These policies apply to any activities undertaken by or on behalf of the Corporation.

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 Corporation reinforces this commitment through the promotion and support of a culture in which all employees and contractors participate and share ownership in health and safety management. 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 consistently conducting all activities within the environmental regulations that govern the oil and gas industry within each of its operating jurisdictions and to also 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.

The Safety and Social Responsibility Committee of the Corporation's board of directors is responsible for review of the policies, oversight and continuous improvement of the S&SR management system, ensuring that Corporation's activities are planned and executed in a safe and responsible manner and review to ensure there are adequate systems in place to support ongoing compliance. Additionally, the committee is responsible for oversight of all results and action plans that have been initiated or proposed by the Corporation with respect to S&SR.

Health and Safety

The Corporation's employee recordable injury frequency rate was 0.70 injuries per 200,000 man hours compared to 0.82 injuries per 200,000 man hours in 2010. The Corporation's contractor total recordable injury frequency decreased from 1.97 injuries per 200,000 man hours in 2010 to 1.63 injuries in 2011. The Corporation's 2011 combined employee/contractor recordable injury frequency rate was 1.32 injuries per 200,000 man hours, a decrease from 1.53 injuries per 200,000 man hours in 2010. The Corporation's employee and contractor safety performance was above the Canadian Association of Petroleum Producers ("**CAPP**") 2010 industry average.

In 2011, the Corporation implemented a Sustainability Information Management System ("SIMS") to maintain its corporate health and safety and social responsibility performance data. In conjunction with the SIMS system, the Corporation revised its Incident Management Standard to align with current industry standards and best practice.

Health and safety risks influence workplace practices, operating costs and the establishment of regulatory standards. The Corporation maintains a comprehensive 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 CAPP Responsible Canadian Energy Program to develop and 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 Corporation continues to develop and implement prevention measures and safety management program improvements that are designed to support its focus and commitment for an injury-free workplace. Management of the Corporation maintains its commitment towards improved health and safety performance by supporting a culture in which all employees and contractors embrace safety in their day-to-day activities.

Environment

The Corporation is committed to meeting its responsibilities to protect the environment through a variety of programs and actively monitors its 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 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 2011 totalled $16.9 million ($12.0 million on operated properties, $4.9 million on non operated properties). The Corporation's U.S. abandonment capital expenditures totalled $4.8 million. The Corporation received 48 reclamation certificates in 2011 by returning sites to that of equivalent land capability, which contributes to its overall reduction in liabilities;
- The Corporation conducts annual property reviews in Canada with specific corrosion risk management goals designed to ensure compliance with health, safety and environmental legislation and regulations and in 2011, 85 areas were reviewed. For the Corporation's U.S. properties, integrity inspections were completed at 35 locations in 2011;
- The Corporation continues to manage risk through the implementation of a Pipeline Risk Program and various other pipeline integrity activities including inspection of pipelines at water crossings. The Corporation reviews each pipeline system annually. The Corporation is currently enhancing this program to include a wider range of hazards to identify and mitigate risks to decrease future significant pipeline failure incidents;
- The Corporation continued its internal facility inspections program and completed 20 inspections at major Canadian facilities in 2011. In 2011, the average score of environment and regulatory compliance resulting from the internal inspection program was 89%. The Corporation also completed nine environment and regulatory compliance audits in 2011 at its Canadian facilities and averaged a score of 90% compliance; and
- The Corporation normally calculates its greenhouse gas emissions for the prior calendar year in the first and second quarter of the current year. Therefore, results for 2011 are not yet available. However the Corporation has estimated its 2011 direct emissions to be approximately 530,000 carbon dioxide equivalent tonnes per year. The estimated numbers will be adjusted as additional data becomes available. In 2011, Enerplus completed 183 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 cost of this tax was approximately $729,000 in 2011. In addition, the Corporation is required to report third party verified greenhouse gas emissions annually to the government of British Columbia under the *Cap and Trade Act* (British Columbia) and the first of these reports was submitted on March 31, 2011. In Alberta, while the Corporation does not operate facilities that qualify as large emitters, the Corporation is required to pay its share of the costs at non-operated large emitter facilities. In 2011, this cost was approximately $141,000. 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 first of these reports will be submitted to the U.S. Environmental Protection Agency in late September 2012 for the 2011 operational year. 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 regulations and adheres to the recently released 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 water required during the fracturing process. In addition to water conservation efforts, the Corporation employs well casing integrity best practices to mitigate risks of impacts to surface and groundwater. 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.

The Corporation carries insurance to cover a portion of its property losses, liability and business interruption. 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, 2011, the Corporation employed a total of 712 persons, including full-time benefit and payroll consultants, 635 of whom were in Canada and 77 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 on January 5, 2011 and on the Corporation's EDGAR profile at www.sec.gov on January 5, 2011.

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's board of directors on the Common Shares and to share in the remaining property of the Corporation upon liquidation, dissolution or winding-up.

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

Effective January 1, 2011, the Corporation adopted the Shareholder Rights Plan, which was approved by the Fund's unitholders concurrently with their approval of the Conversion on December 9, 2010. The Shareholder Rights Plan must next be renewed and approved by the Corporation's shareholders at the annual meeting to be held in 2013, failing which it will expire at such time. 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 as a "Security holder document" on January 5, 2011 on the Corporation's SEDAR profile at www.sedar.com, was filed on the Corporation's EDGAR profile at www.sec.gov on January 5, 2011, 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$413.2 million and CDN$40 million principal amounts were outstanding at December 31, 2011. The Senior Unsecured Notes were originally issued in the amounts of (i) US$175 million on June 19, 2002 (of which US$105 million principal amount remained outstanding at December 31, 2011), (ii) US$54 million on October 1, 2003 (of which US$43.2 million principal amount remained outstanding at December 31, 2011), and (iii) US$225 million, US$40 million and CDN$40 million on June 18, 2009. Certain terms of the Senior Unsecured Notes are summarized below:

Issue Date	Original Principal	Remaining Principal	Coupon Rate	Interest Payment Dates	Maturity Date	Term
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 5 equal annual instalments beginning June 18, 2017
October 1, 2003	US$54 million	US$43.2 million	5.46%	April 1 and October 1	October 1, 2015	Principal payments required in equal annual instalments on October 1, 2012 to 2015
June 19, 2002	US$175 million	US$105 million	6.62%	June 19 and December 19	June 19, 2014	Principal payments required in equal annual instalments on June 19, 2012 to 2014

For additional information regarding the Senior Unsecured Notes, see Note 8 to the Corporation's audited consolidated financial statements for the year ended December 31, 2011. See also "*Material Contracts and Documents Affecting Securityholder Rights*".

BANK CREDIT FACILITY

As of December 31, 2011, the Corporation had $446 million drawn on a $1.0 billion unsecured, covenant-based credit facility with a syndicate of financial institutions maturing October 13, 2014. 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, 2011. See also "*Material Contracts and Documents Affecting Securityholder Rights*".

Dividends and Distributions

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, with the 10th day of each calendar month (or the immediately preceding business day) as a dividend record date and the 20th day of such month (or the nearest business day) as the corresponding dividend payment date. 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 cash distributions paid by the Fund to its unitholders in 2009 and 2010 (as well as in January 2011 with respect to the Fund's final distribution record date of December 31, 2010), and the dividends paid or declared by the Corporation in 2011 and January through March of 2012:

Month	**2012**	**2011**	**2010**	**2009**
January	$ 0.18	$ 0.18	$ 0.18	$ 0.25
February	0.18	0.18	0.18	0.18
March	0.18	0.18	0.18	0.18
April	N/A	0.18	0.18	0.18
May	N/A	0.18	0.18	0.18
June	N/A	0.18	0.18	0.18
July	N/A	0.18	0.18	0.18
August	N/A	0.18	0.18	0.18
September	N/A	0.18	0.18	0.18
October	N/A	0.18	0.18	0.18
November	N/A	0.18	0.18	0.18
December	N/A	0.18	0.18	0.18

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"*.

DIVIDEND REINVESTMENT PLAN

The Corporation has in place a dividend reinvestment plan under which eligible Canadian-resident shareholders may elect to apply the dividends paid on their Common Shares towards the purchase of additional Common Shares from treasury of the Corporation at a 5% discount to the ten day weighted average trading price of the Common Shares on the TSX immediately prior to the applicable dividend payment date. For additional information on the Corporation's dividend reinvestment plan and to obtain copies of the documents related to the plan, see the Corporation's website at www.enerplus.com under "*Investor Information – Shareholder Information*".

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 of similar size, 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 Enerplus 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 discussion below focuses on the Canadian oil and natural gas industry (and particularly Alberta, Saskatchewan and British Columbia, which accounted for approximately 76% of the Corporation's 2011 production). The Corporation also owns oil and natural gas properties and related assets in the province of Manitoba and in Montana, North Dakota, Pennsylvania, West Virginia, Maryland, Wyoming and Utah 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 the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

PRICING AND MARKETING – OIL

Producers of oil negotiate sales contracts directly with oil purchasers, resulting in a market price for oil. The price depends, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance and other contractual terms, as well as the world price of oil. Crude oil exported from Canada is subject to regulation by the National Energy Board (the "**NEB**") and the Government of Canada. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires the approval of the Governor in Council.

PRICING AND MARKETING – NATURAL GAS

The price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. 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. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic metres per day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires the approval of the Governor in Council.

The governments in the Canadian provinces where the Corporation operates also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

THE NORTH AMERICAN FREE TRADE AGREEMENT

On January 1, 1994, the North American Free Trade Agreement ("**NAFTA**") became effective among the governments of Canada, the United States of America and Mexico. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply. All three countries are generally prohibited from imposing minimum export or import price requirements and, except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings, minimum or maximum import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

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 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 and upon commencement of production, royalties and production taxes are paid in respect of oil and natural gas produced from federal, state and freehold lands. The royalty and production tax regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than 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 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) (the "**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 (the "**FBIR**") and involve allotee lands, which are lands that are administered by the Bureau of Indian Affairs (the "**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 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 their own statutes that operators must follow both prior to drilling and following drilling including notification requirements and to provide compensation for lost land use and surface damages. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

ENVIRONMENTAL REGULATION

The oil and natural gas industry is subject to environmental regulation pursuant to federal, provincial/state and local legislation. This legislation provides for environmental protection and applies restrictions and prohibitions regarding disturbances and releases or emissions of various substances produced or utilized in association with oil and gas industry operations. In addition, legislation requires that well, pipeline and facility sites are abandoned and reclaimed to the satisfaction of the applicable authorities. 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. Compliance with such legislation can require significant expenditures. A breach of such legislation 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.

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, environmental compliance is governed by the *Environmental Protection and Enhancement Act* (Alberta) and the *Oil and Gas Conservation Act* (Alberta), both of which impose environmental responsibilities on oil and natural gas operators and working interest holders in Alberta and impose penalties, which may be significant, for violations. In Saskatchewan, environmental compliance is governed by the *Environmental Management and Protection Act* (Saskatchewan) and the *Oil and Gas Conservation Act* (Saskatchewan). Oil and gas activities in Manitoba are regulated by the *Oil and Gas Act* (Manitoba) and environmental protection and management measures are outlined in *The Environment Act* (Manitoba).

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 *Cap and Trade Act* (British Columbia) (the "**BCCTA**") which requires third party verified greenhouse gas emissions to be reported annually. See "*Supplemental Operational Information – Health, Safety and Environment – Environment*". The Corporation is subject to the Reporting Regulation under the BCCTA and submitted a third party verified greenhouse gas emissions report on March 31, 2011. 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 in order 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 its 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, it is expected that the Province of Saskatchewan will proclaim *The Management and Reduction of Greenhouse Gases Act* (Saskatchewan) during 2012, 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 and county levels of government. At the federal level, planning and permitting is primarily regulated by the U.S. Department of Interior for operations on public and tribal lands under the *Federal Land Policy and Management Act* and *National Environmental Policy Act*. Environmental conservation and cultural and natural resources protection at the federal level are administered by numerous agencies under multiple statutes including the following:

- *Archaeological Resources Protection Act* (National Park Service);
- *Endangered Species Act* (U.S. Fish and Wildlife Service);
- *Migratory Bird Treaty Act* (U.S. Fish and Wildlife Service); and
- *Noxious Weed Act* (U.S. Department of Agriculture).

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*, *Clean Water Act*, *Resource Conservation and Recovery Act*, *Emergency Planning and Community Right-to-Know Act* and the *Safe Drinking Water Act*.

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, from the Colorado Oil and Gas Conservation Commission, the Maryland Department of the Environment, the Montana Board of Oil and Gas and the Department of Environmental Quality, the North Dakota Department of Health and the Oil & Gas Division, and the Pennsylvania Department of Environmental Protection. In addition to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, state water quality, fish, wildlife, visual quality, transportation, noise, spills and incidents, 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, under Subpart W, 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 will submit the appropriate report to the U.S. EPA commencing September 2012.

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. However the Corporation minimizes the potential of these impacts to U.S. operations in many ways including through the participation and membership in Trade Organizations such as the Colorado Oil and Gas Association, the Western Energy Alliance, the Public Lands Advocacy, the Marcellus Shale Coalition, the American Petroleum Institute, and the West Virginia Oil and Natural Gas Association. 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 regulation. 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 1994, the United Nations Framework Convention on Climate Change came into force, and three years later participating countries agreed to the only legally binding international agreement to reduce greenhouse gas emissions under the Kyoto Protocol. Upon ratification, participating countries are to reduce their emissions of carbon dioxide and other greenhouse gases 6% below 1990 levels during the four years between

2008 and 2012. Canada ratified the Kyoto Protocol in late 2002. However, in late 2011, the Government of Canada formally withdrew from the Kyoto Protocol, opting to keep in line with U.S. action and pursuing a regulatory approach that would impose sector by sector rules. 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 – Enerplus' 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 may adversely impact Enerplus' operations and result in increased operating and capital costs*".

WORKER SAFETY

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 accident 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 Common Shares. 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.

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 may fluctuate 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 seek 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; (v) the production and storage levels of North American natural gas 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 capacity; (viii) the effect of world-wide energy conservation and greenhouse gas reduction measures and the price and availability of alternative fuels; and (ix) government regulations.

Any 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.

The Corporation's proposed strategy, including its proposed increased focus on growth-oriented projects and acquisitions, may expose the Corporation's operations to increased risks.

As described under "*General Development of the Business*" and "*Business of the Corporation*", the Corporation is continuing to transition from an income model to a growth and income-oriented model. This transition includes an increased emphasis on higher risk growth plays such as the Tight Oil, Marcellus Shale Gas and Deep Gas play types, which may expose the Corporation to additional risks in its business and operations than has historically been the case, and there can be no assurance that the transition will be made successfully and will not result in adverse financial or operational results to the Corporation. These types of plays are earlier stage development projects (and in certain cases are more exploration-oriented in nature) than the Corporation has historically participated in and, 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 that the Corporation acquires properties or assets with a higher risk exploration profile, the risk associated with such acquisitions and future development of such properties carries similar risks. Additionally, the Corporation may face increased competition in its industry as other former income-oriented issuers also transition to a more growth-oriented corporate model.

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 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 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 the Bank Credit Facility in 2011, and accordingly it currently expires on October 13, 2014. 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.

Additionally, in 2011 the Corporation made aggregate principal repayments on its Senior Unsecured Notes of US$45.8 million (CDN$64.7 million including underlying derivatives). 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's commodity risk management activities could expose it to losses.

The Corporation may use financial derivative instruments and other hedging mechanisms to try 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 exposure, it may forego the benefits it would otherwise experience if commodity prices were to increase. In addition, the Corporation's commodity 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.

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 United States 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 United States dollar may negatively impact the Corporation's net production revenue by decreasing the Canadian dollars the Corporation receives for a given sale in United States 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 United States dollar. The Corporation currently has in place cross-currency and foreign exchange swaps associated with the Senior Unsecured Notes as described in Note 15(c) to the Corporation's audited consolidated financial statements for the year ended December 31, 2011.

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 are highly dependent on its success in developing and exploiting its reserve and resource 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's actual reserves and resources will vary from its reserve and resource 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 reserve or resource 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 reserve and resource 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 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.

Reserve and resource 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.

Reserve and resource 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.

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 has required and will require significant 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.

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.

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 2011, approximately 30% 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 these 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 gross negligence or wilful misconduct.

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) blowouts 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.

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, craterings and fires. 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 damages 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 Marcellus Shale Gas and Bakken oil plays involve certain additional risks and uncertainties. The drilling and completion of wells and operations in the Bakken and in shale gas plays, and in particular the Marcellus shale region, present certain challenges that differ from conventional oil and gas operations. Wells in these plays 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 of the Bakken and the Marcellus shale may be more extensive and complicated than fracturing the geological formations in the Corporation's other areas of operation and requires 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. 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 a contractual or trust related obligation which they may default in satisfying and which may adversely effect 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 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.

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 play types and 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.

A decline in the Corporation's ability to market oil and natural gas production could have a material adverse effect on its production levels or on the price that the Corporation receives for production.

The Corporation's business depends in part upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and processing facilities to provide access to markets for its production. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect the Corporation's ability to produce and market oil and natural gas. New resource plays 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, processing and pipeline infrastructure. For example, pipeline and transportation constraints experienced by oil producers in Montana and North Dakota have become more pronounced as a result of increased drilling and development activities in these regions. Additionally, as exploration and drilling in the Marcellus shale gas play increases, the amount of natural gas and associated NGLs being produced by the Corporation and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If these constraints remain unresolved, the Corporation's ability to transport its production in these regions may be impaired and could adversely impact the Corporation's production volumes or realized prices from these areas.

While the third party pipelines generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of pipeline capacity, and unfavourable economic conditions or financing terms may defer or prevent the completion of certain pipeline projects or gathering systems that are planned for such areas. There are also occasionally operational reasons, including as a result of 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. In such event, the Corporation may have to defer development of or shut in its wells awaiting a pipeline connection or capacity and/or sell its production at lower prices than it would otherwise realize or than the Corporation currently projects, which would adversely affect the Corporation's results of and cash flow from 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 competitive resources to draw upon.

Additionally, as the Corporation is subject to taxation as a Canadian corporation beginning in 2011 as a result of the Conversion from an income trust to a corporation, 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.

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. See "*Industry Conditions – Environmental Regulation*" for a summary of certain proposals. 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.

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 and the ability of such water to be recycled. 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. 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 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 and environmental matters.

Changes in tax and other laws and interpretations of those laws may adversely affect the Corporation and its shareholders.

Income tax laws, including tax laws 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 shareholders. Additionally, 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. 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.

Government regulations and required regulatory approvals 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, 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 cities such as Philadelphia and New York have called for bans on drilling in their local watersheds. Similarly, Canadian regulatory bodies have enhanced their oversight of and reporting obligations associated with fracturing procedures. More activity by the Corporation on Indian land 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 United States governments are considering legislation to reduce emissions of greenhouse gases. 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 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.

In Alberta, the conversion of the Corporation's business from an income trust to a corporation effective January 1, 2011 pursuant to the Conversion included the amalgamation of different Energy Resources Conservation Board ("**ERCB**") licensees into one. As part of the ERCB compliance strategy, the Corporation's compliance performance will be monitored for an unacceptable risk rate, ratio, percentage, or number of non-compliance's in either the same or different compliance categories that, prior to the amalgamation, were distributed amongst many license holders. If more than two ERCB high risks are received in the same category, the Corporation could be put on "Monitoring" or "Persistent" non-compliance status, which could lead to enforcement consequences.

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

Under IFRS, when indicators of impairment exist, the carrying value of the Exploration and Evaluation ("**E&E**") assets as well as each Cash Generating Unit ("**CGU**"), including goodwill attributed to the CGU, is compared to its recoverable amount. The recoverable amount is defined as the higher of the fair value less cost to sell or value in use. A decline in oil and gas prices may be an indicator of impairment and may result in a write-down of the value of the Corporation's assets. While these write-downs would not affect cash flow from operations, the charge to earnings may be viewed unfavourably in the market. Other than goodwill impairments, E&E or CGU asset write-downs may also be reversed in future periods should the conditions that caused impairment reverse. Accordingly the Corporation would thereby reverse all, or a portion of previously recorded charges to earnings.

The loss of the Corporation's key management and other personnel could impact its business.

Shareholders are entirely dependent on the management of the Corporation with respect to the acquisition of oil and natural gas properties and assets, the exploration for and development of additional reserves and resources and the management and administration of all matters relating to the Corporation and its properties and assets. The loss of the services of key individuals could have a detrimental effect on the Corporation. Further, the Corporation's recent acquisitions and activities in various play types will require different skill sets than those needed in developing its traditional asset base. There is no assurance that the Corporation will be able to attract and retain personnel with the technical expertise necessary to develop such properties, which could adversely effect 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, interest rates and the comparability of the Common Shares to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

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 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 local taxes on such dividends and these taxes may change from time to time. For example, in the United States, the "qualified dividend" rate of 15% tax applied to the Corporation's dividends under current U.S. federal income tax laws was scheduled to expire at the end of 2010 but was extended through 2012, but there is no assurance that this reduced tax rate will be extended beyond such date in its present form by the U.S. government.

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 reserve 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 United States 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 United States courts of liabilities based solely upon the United States 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 and the United States composite trading information for 2011.

	TSX			U.S. Composite Trading		
Month	**High**	**Low**	**Volume**	**High**	**Low**	**Volume**
January	$32.83	$30.80	14,781,041	US$33.29	US$30.78	3,638,328
February	32.46	30.10	9,587,850	32.93	30.51	3,677,338
March	31.78	27.48	8,658,504	32.72	27.75	4,442,140
April	31.03	29.03	5,729,006	32.44	30.05	2,824,785
May	31.49	28.84	7,900,348	32.86	29.69	5,226,203
June	31.54	29.03	7,868,833	32.53	29.61	4,953,962
July	31.05	29.34	6,761,500	32.28	30.46	3,635,289
August	30.20	24.25	14,124,811	31.89	24.43	8,559,746
September	28.73	24.66	9,662,084	29.44	23.94	4,899,878
October	28.48	23.00	9,908,264	28.69	21.67	5,355,870
November	29.39	25.25	10,474,688	28.97	24.18	4,212,609
December	26.96	24.49	9,579,416	26.46	23.52	4,208,718

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 director of the Corporation are set forth below.

Name and Residence	Director Since	Principal Occupation for Past Five Years
David H. Barr(6) Woodlands, Texas, U.S.A.	July 2011	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.
Edwin V. Dodge(4)(6) Vancouver, British Columbia, Canada	May 2004	Corporate director.
Robert B. Hodgins(2)(3) Calgary, Alberta, Canada	November 2007	Independent businessman.
Gordon J. Kerr Calgary, Alberta, Canada	May 2001	President and Chief Executive Officer of Enerplus.
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 until 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.
Douglas R. Martin(1) Calgary, Alberta, Canada	September 2000	President of Charles Avenue Capital Corp. (a private merchant banking company).
David P. O'Brien(3)(7) Calgary, Alberta, Canada	March 2008	Corporate director, including Chairman of Encana Corporation (a TSX and NYSE-listed oil and gas company) and Chairman of the Royal Bank of Canada (a TSX and NYSE-listed Canadian chartered bank).
Elliott Pew(2)(5) Boerne, Texas, U.S.A.	September 2010	Director of Common Resources II, L.L.C. (a private oil and gas company) since May 2010. Prior thereto, Chief Operating Officer of Common Resources L.L.C. (a private oil and gas company) from March 2007 to May 2010.
Glen D. Roane(2)(3) Canmore, Alberta, Canada	June 2004	Corporate director.
W.C. (Mike) Seth(3)(5) Calgary, Alberta, Canada	August 2005	President of Seth Consultants Ltd. (a private consulting firm).
Donald T. West(5)(6)(8) Calgary, Alberta, Canada	April 2003	Independent businessman.
Harry B. Wheeler(2)(4)(8) Calgary, Alberta, Canada	January 2001	President of Colchester Investments Ltd. (a private investment firm).
Clayton H. Woitas(5)(6)(8) Calgary, Alberta, Canada	March 2008	President of Range Royalty Management Ltd. (a private energy company).
Robert L. Zorich(4)(8) Houston, Texas, USA	January 2001	Managing Director of EnCap Investments L.P. (a private firm that provides private equity financing to the oil and gas industry).

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, Elliott Pew, Glen D. Roane and Harry B. Wheeler.
(3) The Corporate Governance & Nominating Committee is currently comprised of Glen D. Roane as Chairman, Robert B. Hodgins, David P. O'Brien and W.C. (Mike) Seth.
(4) The Compensation & Human Resources Committee is currently comprised of Robert L. Zorich as Chairman, Edwin V. Dodge, Susan M. MacKenzie and Harry B. Wheeler.
(5) The Reserves Committee is currently comprised of W.C. (Mike) Seth as Chairman, Susan M. MacKenzie, Elliott Pew, Donald T. West and Clayton H. Woitas.
(6) The Safety & Social Responsibility Committee is currently comprised of Edwin V. Dodge as Chairman, David H. Barr, Donald T. West and Clayton H. Woitas.
(7) Mr. O'Brien was a director of Air Canada in April 2003 when Air Canada filed for protection under the *Companies' Creditors Arrangement Act* (Canada). Mr. O'Brien resigned as a director from Air Canada in November 2003.
(8) Messrs. West, Wheeler, Woitas and Zorich are not standing for re-election at the 2012 annual meeting of shareholders of the Corporation.

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
Gordon J. Kerr Calgary, Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of Enerplus.
Ian C. Dundas Calgary, Alberta, Canada	Executive Vice President & Chief Operating Officer	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.
Dana W. Johnson Denver, Colorado, U.S.A.	President, U.S. Operations	President, U.S. Operations of Enerplus since May 2008. Prior thereto, Senior Vice President and Chief Operating Officer of Quicksilver Resources Canada Inc., (a wholly-owned subsidiary of NYSE-listed Quicksilver Resources Inc., an oil and gas exploration and production company).
Raymond J. Daniels Calgary, Alberta, Canada	Senior Vice President, Canadian Operations	Senior Vice President, Canadian Operations of the Corporation since April 2011. Prior thereto, Vice President, Development Services of Enerplus since July 2009. Prior thereto, Vice President, Oil Sands of Enerplus since December 2007. Prior thereto, Vice President, Surmont Development, Surmont Opportunity Manager and Asset Manager, Central Region, each with ConocoPhillips Canada.
Eric G. Le Dain Calgary, Alberta, Canada	Senior Vice President, Strategic Planning, Reserves & Marketing	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. Prior thereto, Vice President, Marketing of Enerplus since September 2006.
Jo-Anne M. Caza Calgary, Alberta, Canada	Vice President, Corporate & Investor Relations	Vice President, Corporate & Investor Relations of Enerplus since January 2008. Prior thereto, Vice President, Investor Relations of Enerplus.
Rodney D. Gray Calgary, Alberta, Canada	Vice President, Finance	Vice President, Finance of Enerplus.
Robert A. Kehrig Calgary, Alberta, Canada	Vice President, Resource Development	Vice President, Resource Development of Enerplus since October 2008. Prior thereto, Manager in Enerplus' Business Development group.
David A. McCoy Calgary, Alberta, Canada	Vice President, Corporate Services, General Counsel & Corporate Secretary	Vice President, Corporate Services, General Counsel & Corporate Secretary of the Corporation since April 2011. Prior thereto, Vice President, General Counsel & Corporate Secretary of Enerplus.
Brien A. Perry Calgary, Alberta, Canada	Vice President, Human Resources	Vice President, Human Resources of the Corporation since November 2011. Prior thereto, Manager of Human Resources Programs and Services since June 2007. Prior thereto, Human Resources Manager at Conoco Phillips Canada.
P. Scott Walsh Airdrie, Alberta, Canada	Vice President, Information Systems	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	Vice President, Land of Enerplus since November 2008. Prior thereto, Vice President, Land at Avant Garde Energy Corp. (a private oil and gas exploration and production company) since 2008. Prior thereto, independent consultant since 2007. Prior thereto, Vice President, Land of Zargon Oil & Gas Ltd. (a subsidiary of Zargon Energy Trust, an oil and gas income trust).
Jodine J. Jenson Labrie Calgary, Alberta, Canada	Controller, Finance	Controller, Finance of Enerplus.

COMMON SHARE OWNERSHIP

As of March 2, 2012, the directors and officers of the Corporation named above beneficially own, or control or exercise direction over, directly or indirectly, an aggregate of 1,742,328 Common Shares, representing approximately 0.89% 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 D 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 2011 a party to, and none of the Corporation's property is or was during 2011 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, 2011, 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 Enerplus since January 1, 2009 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 Fund's EDGAR profile at www.sec.gov, if they were filed after to the January 1, 2011 Conversion:

1. Bank Credit Facility, together with the First Amending Agreement, Second Amending Agreement, Third Amending Agreement and Fourth Amending Agreement (March 18, 2008);
2. Fifth Amending Agreement to the Bank Credit Facility (July 21, 2010);
3. Sixth Amending Agreement to the Bank Credit Facility (October 21, 2011);
4. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2002, together with the First Amendment and Second Amendment (March 18, 2008);
5. Third Amendment to the Note Purchase Agreement for the Senior Unsecured Notes issued in 2002 (SEDAR – November 10, 2010; EDGAR – November 11, 2010);
6. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2003, together with the First Amendment (March 18, 2008);
7. Second Amendment to the Note Purchase Agreement for the Senior Unsecured Notes issued in 2003 (SEDAR – November 10, 2010; EDGAR – November 11, 2010); and
8. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2009 (SEDAR – June 23, 2009; EDGAR – June 25, 2009).

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 and bylaws of the Corporation (January 5, 2011); and
2. the Shareholder Rights Plan, as described under "*Description of Share Capital – Shareholder Rights Plan*" (January 5, 2011).

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, 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. Haas prepared the Haas Report in respect of the reserves and contingent resources attributable to the Corporation's interests in the Marcellus Properties, a summary of which is contained in this Annual Information Form. As of the date of the Haas Report, the designated professionals of Haas, as a group, beneficially owned, directly or indirectly, less than 1% of the outstanding Common Shares.

The independent auditor of the Corporation is Deloitte & Touche LLP, Independent Registered Chartered Accountants, Calgary, Canada. Deloitte & Touche LLP has confirmed that it is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta, the rules of the United States Securities Act of 1933, as amended, and the applicable rules and regulations adopted by the U.S. Securities and Exchange Commission 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 2012 annual and special 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, 2011. 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 final page of this Annual Information Form.

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

January 30, 2012

Enerplus Corporation
3000, 333 – 7th Avenue SW
Calgary, Alberta
T2P 2Z1

Attention: The Board of Directors of Enerplus Corporation

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator of Enerplus Corporation – Canadian Properties (the "Company")

To the Board of Directors of Enerplus Corporation (the "Company"):

1. We have evaluated and reviewed the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011 estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation and review.

   We carried out our evaluation and review 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 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 a discount rate of 10 percent, included in the reserves data of the Company evaluated and reviewed by us, for the year ended December 31, 2011, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
		(in $ thousands)			
January 30, 2012	Canada	–	$ 2,323,493	$ 697,877	$ 3,021,370

5. In our opinion, the reserves data respectively evaluated and reviewed by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.
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
January 30, 2012

January 30, 2012

Enerplus Resources (USA) Corporation
1300 Wells Fargo Center
Denver, Colorado, USA
80203

Attention: The Board of Directors of Enerplus Corporation

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator of Enerplus Resources (USA) Corporation – U.S. West (the "Company")

To the Board of Directors of Enerplus Corporation (the "Company"):

1. We have evaluated and reviewed the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011 estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation and review.

   We carried out our evaluation and review 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 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 a discount rate of 10 percent, included in the reserves data of the Company evaluated and reviewed by us, for the year ended December 31, 2011, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
		(in US$ thousands)			
January 30, 2012	United States	–	1,943,540	39,445	1,982,985

5. In our opinion, the reserves data respectively evaluated and reviewed by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.
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
January 30, 2012

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

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

1. We have evaluated the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserve data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
				(US$ thousands)		
Haas Petroleum Engineering Services, Inc.	Estimate of Reserves and Future Net Revenue to the Enerplus Corporation Interest as of December 31, 2011, dated January 17, 2012	Maryland, Pennsylvania and West Virginia, USA	–	193,864	–	193,864

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.
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:

HAAS PETROLEUM ENGINEERING SERVICES, INC.
Dallas, Texas, U.S.A.
January 17, 2012
F-002950

"*Robert W. Haas*"

Robert W. Haas, P.E.
President

APPENDIX C

Appendix C – 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, 2011, 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

"*Gordon J. Kerr*"

Gordon J. Kerr
President & Chief Executive Officer

"*Ian C. Dundas*"

Ian C. Dundas
Executive Vice President & Chief Operating Officer

"*W.C. (Mike) Seth*"

W.C. (Mike) Seth
Director

"*Donald T. West*"

Donald T. West
Director

March 9, 2012

Appendix D – 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 D.

B. COMPOSITION OF THE AUDIT & RISK MANAGEMENT COMMITTEE

The current members of the Committee are Robert B. Hodgins (Chairman), Elliott Pew, Glen D. Roane and Harry B. Wheeler. 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) • Fairborne Energy Ltd. (oil and gas exploration and production company) • MGM Energy Corp. (oil and gas exploration and production company) • Skope Energy Inc. (oil and gas exploration and production company) • MEG Energy Corp. (oil sands company) • Cub 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.
Mr. Elliott Pew (B.Sc., M.A.) (Director since September 2010) Other Public Directorships • None	Mr. Pew is a director of Common Resources II, LLC (a private oil and gas company) located in The Woodlands, Texas. Mr. Pew was a co-founder of Common Resources LLC and served as its Chief Operating Officer from March 2007 until it was sold in May 2010. Prior thereto, Mr. Pew was Executive Vice President, Exploration of Newfield Exploration Company (an NYSE-listed oil and gas company) from November 2004 to December 2006 where he led the company's diversification efforts onshore in the late 1990s in addition to leading the company's exploration program, including the formation of the deep water Gulf of Mexico business unit. Prior thereto, Mr. Pew was Senior Vice President, Exploration with American Exploration Corp. Mr. Pew is a Geology graduate of Franklin and Marshall College and holds an M.A. in Geology from the University of Texas.

Name (Director Since)	Principal Occupation and Biography
Mr. Glen D. Roane (B.A., MBA) (Director since June 2004) <u>Other Public Directorships</u> • Badger Daylighting Ltd. (provider of non-destructive excavation services) • Logan International Inc. (oil and gas service business) • SilverBirch Energy Corporation (oil sands company) • Compton Petroleum Corporation (oil and gas exploration and production 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.
Mr. Harry B. Wheeler (B.Sc. (Geology)) (Director since January 2001) <u>Other Public Directorships</u> • Nil	Mr. Wheeler has been the President of Colchester Investments Ltd., a private investment firm, since 2000. From 1962 to 1966, Mr. Wheeler worked with Mobil Oil in Canada and Libya and from 1967 to 1972 was employed by International Resources Ltd., in London, England and Denver, Colorado. He was a Director of Quintette Coal Ltd., Vice President of Amalgamated Bonanza Petroleum Ltd. and operator of his private company before founding Cabre Exploration Ltd. ("Cabre"), a public oil and gas company, in 1980. Mr. Wheeler was Chairman of Cabre until it was acquired by EnerMark Income Fund (a predecessor of Enerplus) in December 2000. Mr. Wheeler is currently a director of Magellan Resources Ltd. and Knowledge Energy Inc., private oil and gas companies. Mr. Wheeler graduated from the University of British Columbia in 1962 with a degree in Geology.

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 & Touche LLP in 2011 and 2010 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 & Touche LLP described above is compatible with maintaining that firm's independence from the Corporation.

E. EXTERNAL AUDITOR SERVICE FEES

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

	2011	2010
	(in $ thousands)	
Audit fees[(1)]	**$ 855.8**	$ 809.3
Audit-related fees[(2)]	**–**	–
Tax fees[(3)]	**504.7**	212.1
All other fees[(4)]	**–**	57.0
	$ 1,360.5	$ 1,078.4

Notes:

(1) Audit fees were for professional services rendered by Deloitte & Touche LLP for the audit of Enerplus' annual financial statements and reviews of Enerplus' 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 Enerplus' 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 Enerplus' 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 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 Chairman of the Committee shall be designated by the Board, provided that if the Board does not so designate a Chairman, the members of the Committee, by majority vote, may designate a Chairman. 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.

Because of the Committee's demanding role and responsibilities, the Corporate Governance and Nominating Committee reviews any invitation to Committee members to join the audit committee of any other company or corporation. Where a member of the Committee simultaneously serves on the audit committee of more than three (3) public companies, including the Committee, the Board determines whether such simultaneous service impairs the ability of such member to serve effectively on the Committee.

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 authority to fix 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 Chairman 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, including the proposed fees thereof;
2. Review and approve the Corporation's external auditors' annual engagement letter;
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-approving 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 Chairman 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 financial results 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 financial documents;
   (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);
   (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.

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