ANNUAL INFORMATION FORM

For the year ended December 31, 2018

February 22, 2019

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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, Contingent Resources, and Production Information*" in this Annual Information Form and under *"Note to Reader Regarding Disclosure of Contingent Resources Information"* in Appendix A. All references to "Annual Information Form" include this Annual Information Form of the Corporation dated February 22, 2019 for the year ended December 31, 2018 and all appendices hereto.**

"**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 at December 31, 2018, the Corporation's $800 million unsecured, covenant-based revolving credit facility with a syndicate of financial institutions. See "*Description of Capital Structure – Bank Credit Facility*" and "*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) Canada and the Canadian Institute of Mining, Metallurgy and Petroleum (Petroleum Society), as amended from time to time

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

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

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

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

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

"ESG" means environmental, social and governance

"**Enerplus**" means (i) on and after January 1, 2011, the Corporation and, where the context requires, 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

"**EOR**" mean enhanced oil recovery, as described in more detail under "*Business of the Corporation – Description of Properties*"

"**Financial Statements**" means the audited consolidated financial statements of the Corporation as at December 31, 2018 and 2017 and for three years ended December 2018, 2017 and 2016

"**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

"GLJ" means GLJ Petroleum Consultants, independent petroleum consultants

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

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent petroleum consultants

"**McDaniel Reports**" means, collectively, the independent engineering evaluations of certain of the Corporation's oil, natural gas liquids and natural gas reserves in Canada and certain of the Corporation's oil, natural gas liquids and natural gas reserves in the United States, prepared by McDaniel effective December 31, 2018, utilizing the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2019

"**MD&A**" means management's discussion and analysis for the year ended December 31, 2018

"**NCIB**" means normal course issuer bid

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

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

"**NSAI Report**" means the independent engineering evaluation of the Corporation's shale gas reserves and contingent resources in the Marcellus properties prepared by NSAI effective December 31, 2018, utilizing the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2019

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

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

"**Senior Unsecured Notes**" means, as at December 31, 2018, the US$489 million principal amount and CDN$30 million principal amount of outstanding senior unsecured notes issued by Enerplus. See "*Description of Capital Structure – Senior Unsecured Notes*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*"

"**Shareholder Rights Plan**" means the amended and restated shareholder rights plan agreement between the Corporation and Computershare Trust Company of Canada, as rights agent, dated as of May 6, 2016. See "*Description of Capital Structure – Shareholder Rights Plan*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*"

"Sproule" means Sproule Associates Limited, independent petroleum consultants

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

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

"**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 gravity, a measure of how heavy or light a petroleum liquid is compared to water
bbls	barrels, with each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/day	barrels per day
Bcf	one billion cubic feet
BcfGE(1)	one billion cubic feet of natural gas equivalent
BOE(1)	barrels of oil equivalent
BOE/day(1)	barrels of oil equivalent per day
GJ	gigajoule; equal to one thousand million joules
Mbbls	one thousand barrels
MBOE(1)	one thousand barrels of oil equivalent
Mcf	one thousand cubic feet
Mcf/day	one thousand cubic feet per day
MMBOE(1)	one million barrels of oil equivalent
MMbtu	one million British Thermal Units
MMcf	one million cubic feet
Mt	one million tonnes
NAFTA	North American Free Trade Agreement
NGLs	natural gas liquids
NPV	net present value of future net revenue, discounted at 10%
NYMEX	the New York Mercantile Exchange
USMCA	United States-Mexico-Canada Agreement
WTI	West Texas Intermediate crude oil that serves as the benchmark crude oil for the NYMEX crude oil contract delivered in Cushing, Oklahoma

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

In this Annual Information Form, unless otherwise indicated, all dollar amounts are in Canadian dollars and all references to "**$**" and "**CDN$**" are to Canadian dollars. References to "**US$**" are to U.S. dollars. On December 31, 2018, the exchange rate for one U.S. dollar, expressed in Canadian dollars and based upon the closing rate of the Bank of Canada, was CDN$1.3637.

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, Contingent Resources, and Production Information

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

The oil and gas reserves and operational information of the Corporation contained in this Annual Information Form contains the information required to be included in the Statement of Reserves Data and Other Oil and Gas Information pursuant to NI 51-101 adopted by the Canadian securities regulatory authorities. Readers should also refer to the Report on Reserves Data and Contingent Resources Data by McDaniel and NSAI 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 Contingent Resources and Other Oil and Gas Information contained in this Annual Information Form is December 31, 2018 and the preparation dates for such information are February 5, 2019 for the McDaniel Reports and February 7, 2019 for the NSAI Report.

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

For information regarding contingent resources of the Corporation and its presentation, see Appendix A.

DISCLOSURE OF RESERVES AND PRODUCTION INFORMATION

Presentation of Information

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

In this Annual Information Form, all crude oil and natural gas information includes tight oil and shale gas, respectively, unless expressly indicated that it is being presented on a separate basis. The Corporation's actual oil and natural gas reserves and future production may be greater than or less than the estimates provided in this Annual Information Form. The estimated future net revenue from the production of such oil and natural gas reserves does not necessarily 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 applicable royalties 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, plus royalty interests. Moreover, in accordance with Canadian disclosure requirements, the Corporation has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC generally requires that reserves estimates be prepared using an unweighted average of the closing prices for the applicable commodity on the first day of each of the twelve months preceding the Corporation's fiscal year-end, with the option of also disclosing reserves estimates based upon future or other prices. As a consequence of the foregoing, the Corporation's reserves estimates and production volumes may not be comparable to those made by companies utilizing United States reporting and disclosure standards. Additionally, the SEC prohibits disclosure of oil and gas resources in SEC filings, including contingent resources, whereas Canadian securities regulatory authorities allow disclosure of 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 *"Note to Reader Regarding Disclosure of Contingent Resources Information*" in Appendix A.

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 BcfGEs. BOEs, MBOEs, MMBOEs, and BcfGEs may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

INTERESTS IN RESERVES, CONTINGENT RESOURCES, PRODUCTION, WELLS AND PROPERTIES

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

"**gross**" means:

(i) in relation to the Corporation's interest in production, reserves or contingent resources, 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

(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, reserves or contingent resources, 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

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

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

RESERVES CATEGORIES AND LEVELS OF CERTAINTY FOR REPORTED RESERVES

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

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

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

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

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

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

DEVELOPMENT AND PRODUCTION STATUS

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

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

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

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

DESCRIPTION OF PRICE AND COST ASSUMPTIONS

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

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

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

Presentation of Financial Information

The Corporation presents its financial information in accordance with U.S. GAAP. The Corporation continues to qualify as a foreign private issuer for its U.S. securities filings as fewer than 50% of its shareholders resided in the United States as at June 30, 2018. The Corporation is required to reassess this annually, at the end of the second quarter. See "*Risk Factors – Government policy and/or regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs*".

Forward-Looking Statements and Information

This Annual Information Form contains certain forward-looking statements and forward-looking information (collectively, "forward-looking information") within the meaning of applicable securities laws which are based on the Corporation's current internal expectations, estimates, projections, assumptions, and beliefs. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plan", "intend", "guidance", "objective", "strategy", "should", "believe" and similar expressions are intended to identify forward-looking 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 relied upon unduly. Such forward-looking information speaks only as of the date of this Annual Information Form and the Corporation does not undertake any obligation to publicly update or revise any forward-looking information, except as required by applicable laws.

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

- the quantity of, and future net revenues from, the Corporation's reserves and/or contingent resources
- crude oil, NGLs and natural gas production levels
- commodity prices, foreign currency exchange rates and interest rates
- operating expenditures
- current capital expenditure programs, drilling programs, development plans and other future expenditures, including the planned allocation of capital expenditures among the Corporation's properties and the sources of funding for such expenditures
- supply and demand for oil, NGLs and natural gas
- the Corporation's business strategy, including its asset and operational focus
- future acquisitions and divestments, 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
- the Corporation's tax pools and the time at which the Corporation may incur certain income or other taxes
- treatment of, and compliance by the Corporation with, governmental and other regulatory regimes and tax, environmental and other laws
- future dividends that may be paid by the Corporation

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

The Corporation's current 2019 capital expenditure budget contained in this Annual Information Form assumes: WTI price of between US$50/bbl and US$55/bbl, NYMEX natural gas price of US$3.00/Mcf, and a foreign exchange rate of USD/CDN 1.32.

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

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

- ongoing volatility in market prices for crude oil, NGLs and natural gas, including changes in supply or demand for those products

- actions by governmental or regulatory authorities, including mandated production curtailments or 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 crude oil, NGLs and natural gas production levels
- changes in foreign currency exchange rates, including Canadian currency compared to U.S., and its impact on the Corporation’s operations and financial condition
- changes in interest rates
- changes in development plans by the Corporation or third-party operators
- the ability of the Corporation to comply with debt covenants under the Credit Facilities
- 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 services, third party processing capacity and skilled personnel
- incorrect assessments of the value of acquisitions or divestments, or the failure to complete divestments
- constraints on, or the unavailability of, adequate infrastructure, including pipeline and other transportation capacity, to deliver the Corporation's production to market, whether in the control of the Corporation or not
- 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 North America and worldwide
- 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, including those impacting financial institutions, that could limit commodity market liquidity

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, which are available on the internet under the Corporation's SEDAR profile at www.sedar.com, the Corporation's EDGAR profile at www.sec.gov as part of the annual report on Form 40-F filed with the SEC (together with this Annual Information Form), and on the Corporation's website at www.enerplus.com. Readers are also referred to the risk factors described in this Annual Information Form under "*Risk Factors*" and in other documents the Corporation files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the Corporation or electronically on the internet on the Corporation's SEDAR profile at www.sedar.com, on the Corporation's EDGAR profile at www.sec.gov and on the Corporation's website at www.enerplus.com.

Corporate Structure

ENERPLUS CORPORATION

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

Effective May 11, 2012, the Corporation amended and restated its Articles in connection with the implementation of a stock dividend program. See "*Description of Capital Structure – Common Shares*" and "*Dividends – Stock Dividend Program*".

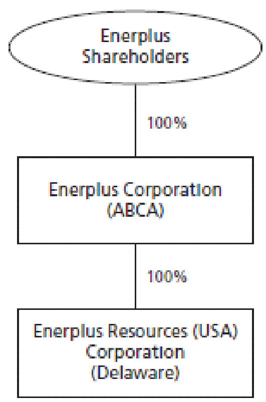
The head, principal and registered office of the Corporation is located at The Dome Tower, 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1. The Corporation also has a U.S. office located at Suite 2200, 950 - 17th Street, Denver, Colorado, 80202-2805. The Common Shares are currently traded on the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

MATERIAL SUBSIDIARIES

As of December 31, 2018, Enerplus USA was the only material subsidiary of Enerplus Corporation. All of the issued and outstanding securities of Enerplus USA are owned by the Corporation.

ORGANIZATIONAL STRUCTURE

The simplified organizational structure of Enerplus Corporation and its material subsidiary as of December 31, 2018 is set forth below.



General Development of the Business

DEVELOPMENTS IN THE PAST THREE YEARS

Developments in 2016

SENIOR NOTES REPURCHASE

The Corporation repurchased a total of US$267 million aggregate principal amount of the Senior Unsecured Notes between 90% of par and par during the first half of 2016, resulting in a gain of $19.3 million being recorded for the year. The repurchases were funded through asset divestment proceeds and the Bank Credit Facility.

FINANCING

On May 31, 2016, the Corporation completed a bought-deal offering of 33,350,000 Common Shares (including 4,300,000 Common Shares issued pursuant to the exercise in full of the over-allotment option granted to the underwriters), at $6.90 per Common Share, for total proceeds of $230,115,000. The net proceeds from the offering were used by the Corporation to reduce indebtedness under the Bank Credit Facility, to fund its capital expenditures, and for general corporate purposes.

SALE OF ASSETS

In 2016, the Corporation realized proceeds of approximately $670 million from the divestment of certain of its non-strategic crude oil and natural gas assets. These divestments included approximately 13,500 BOE/day of production, in aggregate, from crude oil and natural gas assets in Canada, as well as certain non-operated North Dakota assets in the United States. The proceeds from the Corporation's divestment activities were used to fund the Corporation's capital program, repurchase a portion of its Senior Unsecured Notes, as described above, and to reduce amounts outstanding under the Bank Credit Facility.

Developments in 2017

SALE OF ASSETS

In 2017, the Corporation realized proceeds of approximately $56 million, as well as a reduction in its asset retirement obligations of $72 million on a discounted basis (see Note 8 to the Financial Statements), from the divestment of certain of its crude oil and natural gas assets in Canada. These divestments included associated production of approximately 7,700 BOE/day, in aggregate, and reduced the Corporation’s well count by 3,200 wells. The proceeds from the Corporation's divestment activities were used to repay amounts outstanding on its Credit Facilities and general corporate purposes.

Developments in 2018

NORMAL COURSE ISSUER BID

During 2018, the Corporation repurchased an aggregate of 5.9 million Common Shares for $79.0 million, pursuant to its NCIB which will expire on March 25, 2019. As of February 20, 2019, an additional 586,953 Common Shares have been repurchased under the NCIB in 2019.

Business of the Corporation

OVERVIEW

The Corporation's oil and natural gas property interests are located in the United States, primarily in North Dakota, Montana, Colorado and Pennsylvania, as well as in western Canada in the provinces of Alberta, British Columbia and Saskatchewan. Capital spending on these assets in 2018 totaled $593.9 million with over 88% of this focused on the Corporation’s crude oil assets in North Dakota and crude oil properties in Canada.

In the United States, capital spending on the Bakken and Three Forks assets in North Dakota totaled approximately $434.7 million during 2018. In Canada, capital spending of $46.3 million in 2018 was directed to ongoing waterflood implementation at Ante Creek, Alberta, along with drilling and waterflood optimization activities for the Corporation’s other waterflood assets. Capital spending on the Corporation’s natural gas interests in northeast Pennsylvania was $66.2 million. Canadian natural gas properties received a minimal amount of capital during 2018.

In 2018, the Corporation acquired property and land for a total of $25.8 million, including land acquisitions in Colorado and a property swap in North Dakota. In addition, the Corporation received net divestment consideration of $6.9 million primarily related to an acreage swap in North Dakota.

The Corporation's major producing properties generally have related field facilities and infrastructure to accommodate its production. Production volumes for the year ended December 31, 2018 from the Corporation's properties consisted of 54% crude oil and NGLs and 46% natural gas, on a BOE basis. The Corporation's 2018 average daily production was 93,216 BOE/day, comprised of 45,424 bbls/day of crude oil, 4,486 bbls/day of NGLs and 259,837 Mcf/day of natural gas, an increase of approximately 10% compared to 2017 average daily production of 84,711 BOE/day, comprised of 36,935 bbls/day of crude oil, 3,858 bbls/day of NGLs and 263,506 Mcf/day of natural gas. The increase in average daily production in 2018 compared to 2017 is largely attributable to the strong well performance and growth in U.S. production, where the majority of 2018 capital was invested. The Corporation’s 2018 production in the United States was 84% of its total production, with the remaining 16% from Canada. Approximately 57% of the Corporation’s 2018 production was operated by the Corporation, with the remainder operated by industry partners.

As at December 31, 2018, the oil and natural gas property interests held by the Corporation were estimated to contain total proved plus probable gross reserves of approximately 12.7 MMbbls of light and medium crude oil, 28.4 MMbbls of heavy crude oil, 167.2 MMbbls of tight oil, 21.1 MMbbls of NGLs, 41.1 Bcf of conventional natural gas and 1,149.5 Bcf of shale gas, for a total of 427.7 MMBOE. The Corporation's proved reserves represented approximately 70% of total proved plus probable reserves, with approximately 54% of the Corporation's proved plus probable reserves weighted to crude oil and NGLs. See "*Oil and Natural Gas Reserves*".

Unless otherwise noted: (i) all production and operational information in this Annual Information Form is presented as at or, where applicable, for the year ended, December 31, 2018, (ii) all production information represents the Corporation's company interest in production from these properties, which includes overriding royalty interests of the Corporation but is calculated before deduction of royalty interests owned by others, and (iii) all references to reserves volumes represent gross reserves using forecast prices and costs. See "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information*".

SUMMARY OF PRINCIPAL PRODUCTION LOCATIONS

During the year ended December 31, 2018, on a BOE basis, 84% of the Corporation's production was derived from the United States (51% from North Dakota, 44% from Pennsylvania, 4% from Montana, and 1% from Colorado) and 16% from Canada (65% from Alberta, 22% from Saskatchewan and 13% from British Columbia). The following table describes the average daily production from the Corporation's principal producing properties and regions during the year ended December 31, 2018.

2018 Average Daily Production from Principal Properties and Regions

	Products						
	Crude Oil						
Property/Region	**Light and Medium**	**Heavy**	**Tight**	**NGLs**	**Conventional Natural Gas**	**Shale Gas**	**Total**
	(bbls/day)	(bbls/day)	(bbls/day)	(bbls/day)	(Mcf/day)	(Mcf/day)	**(BOE/day)**
United States							
Fort Berthold, North Dakota	-	-	33,090	3,415	-	18,918	39,659
Marcellus, Pennsylvania	-	-	-	-	-	207,993	34,666
Sleeping Giant, Montana	-	-	2,417	1	-	5,382	3,315
DJ Basin, Colorado	-	-	631	-	-	-	631
Other U.S.	-	-	4	6	-	47	16
Total United States	**-**	**-**	**36,142**	**3,422**	**-**	**232,340**	**78,287**
Canada							
Freda Lake/Ratcliffe, Saskatchewan	2,902	-	-	-	-	-	2,902
Medicine Hat Glauc C, Alberta	-	2,736	-	-	271	-	2,781
Tommy Lakes, British Columbia	7	-	-	188	10,553	-	1,954
Giltedge, Alberta	-	1,473	-	-	-	-	1,473
Ante Creek, Alberta	805	-	-	75	2,459	-	1,289
Cadogan, Alberta	-	729	-	6	168	-	763
Pine Creek, Alberta	1	-	-	118	2,702	-	570
Willesden Green, Alberta	1	-	-	178	1,770	-	474
Other Canada	571	57	-	499	9,236	338	2,723
Total Canada	**4,287**	**4,995**	**-**	**1,064**	**27,159**	**338**	**14,929**
Total	**4,287**	**4,995**	**36,142**	**4,486**	**27,159**	**232,678**	**93,216**

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

CAPITAL EXPENDITURES AND COSTS INCURRED

The Corporation invested $593.9 million in its capital program during 2018, with 88% directed to oil-related projects. This increase of 30% compared to 2017 spending of $458.0 million was planned, primarily due to higher cash flow expectations from structural cost reductions in the business and improvements in the Corporation's realized U.S. sales price differentials during 2018. Capital investment during 2018 was focused on the Corporation's U.S. North Dakota Bakken crude oil property (with investment of approximately $434.7 million), its U.S. Marcellus assets (with investment of approximately $66.2 million), its Canadian crude oil properties (with investment of approximately $46.3 million), and its Denver-Julesburg ("**DJ Basin**") assets in Colorado where it invested $39.7 million on the drilling and completion of four delineation wells.

In the financial year ended December 31, 2018, the Corporation made the following expenditures in the categories noted, as prescribed by NI 51-101:

	Property Acquisition Costs			
	Proved	**Unproved**	**Exploration Costs**	**Development Costs**
	($ in millions)			
United States	$ 6.1	$ 15.6	$ 1.0	$ 539.6
Canada	-	3.9	0.6	52.7
Total	$ 6.1	$ 19.5	$ 1.6	$ 592.3

Based on a budgeted commodity price of between US$50 and US$55 per barrel for crude oil and US$3.00 NYMEX for natural gas, the Corporation expects its 2019 exploration and development capital spending to be between $565 million and $635 million, with approximately 93% of this spending projected to be invested in the Corporation's U.S. and Canadian crude oil projects. The Corporation currently expects to invest 80% of its planned 2019 capital spending on its Fort Berthold property in North Dakota, 5% in the DJ Basin of Colorado, and 7.5% on its Canadian crude oil properties. The Corporation intends to spend the remaining 7.5% of its 2019 capital on its non-operated Marcellus natural gas properties in the northeast region of Pennsylvania.

The Corporation intends to finance its 2019 capital expenditure program with cash, internally generated cash flow and/or debt. The Corporation will review its 2019 capital investment plans throughout the year in the context of prevailing economic conditions, commodity prices and potential acquisitions and divestments, making adjustments as it deems necessary. See "*Forward-Looking Statements and Information*".

For further information regarding the Corporation's properties and its 2018 exploration and development activities, see "*Description of Properties*", below.

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes the number and type of wells that the Corporation drilled or participated in the drilling of for the year ended December 31, 2018, in each of Canada and the United States. Wells have been classified in accordance with the definitions of such terms in NI 51-101.

	United States				Canada			
	Development Wells		Exploratory Wells		Development Wells		Exploratory Wells	
Category of Well	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude oil wells	60	47	-	-	21	6	-	-
Natural gas wells	57	8	-	-	1	-	-	-
Service wells	-	-	-	-	9	2	-	-
Dry and abandoned wells	-	-	-	-	-	-	-	-
Total	117	55	-	-	31	8	-	-

For a description of the Corporation's 2019 development plans and the anticipated sources of funding these plans, see "*Capital Expenditures and Costs Incurred*", above.

OIL AND NATURAL GAS WELLS AND UNPROVED PROPERTIES

The following table summarizes, at December 31, 2018, 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**
United States										
Colorado	5	5	-	-	-	-	-	-	36,697	33,863
Montana	243	164	-	-	23	18	-	-	-	-
North Dakota	246	194	-	-	20	15	-	-	-	-
Pennsylvania	-	-	853	91	-	-	72	12	33,124	9,556
Canada										
Alberta	545	231	274	62	348	92	151	44	149,660	104,567
British Columbia	-	-	154	145	-	-	19	9	27,292	22,390
Saskatchewan	629	98	80	23	288	25	157	148	22,215	16,126
Total	1,668	692	1,361	321	679	151	399	212	268,988	186,502

The Corporation expects its rights to explore, develop and exploit on approximately 27,624 net acres of unproved properties in Canada to expire, in the ordinary course, prior to December 31, 2019. 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.

For any properties with no reserves or on unproved lands, the Corporation does not have any significant abandonment and reclamation costs, unusually high expected development costs or operating costs, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations. Operating expenditures and abandonment and reclamation costs for all properties with no reserves or on unproved lands are included in the Corporation's MD&A and asset retirement disclosures in the Financial Statements.

DESCRIPTION OF PROPERTIES

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

For additional information on contingent resources associated with certain of the Corporation's United States and Canadian crude oil and natural gas properties, including estimated volumes of economic contingent resources, see "*Appendix A – Contingent Resources Information"*.

U.S. Crude Oil Properties

OVERVIEW

The Corporation's primary U.S. crude oil properties are located in the Fort Berthold region of North Dakota, the Wattenberg Field of the DJ Basin of Colorado and in Richland County, Montana. The Corporation spent $474.4 million on its U.S. crude oil assets in 2018.

The Corporation has approximately 65,600 net acres of land in Fort Berthold, primarily in Dunn and McKenzie Counties and, on a production basis, operates approximately 93% of its Fort Berthold asset. The Corporation's Fort Berthold property produces a light sweet crude oil (42° API), with some associated natural gas and NGLs, from both the Bakken and Three Forks formations. Fort Berthold production averaged 39,659 BOE/day in 2018. During 2018, the Corporation spent approximately $434.7 million on its operated and non-operated assets in North Dakota, focusing on the execution of its liquids growth plans. During 2018, the Corporation drilled 43.0 net horizontal wells in the Fort Berthold region, targeting both the Bakken and Three Forks formations (consisting of 5.0 net short lateral wells and 38.0 net long lateral wells), with 35.5 net wells brought on-stream. At the end of 2018, the Corporation had 14.5 net drilled uncompleted wells.

The Corporation holds approximately 39,000 net acres (held through leasing and farm-ins) in the DJ Basin of Colorado (northwest Weld County, Wattenberg Field). The Wattenberg Field has been producing since the 1970s and is characterized as having high recoveries and initial production rates, long reserves life and multiple stacked producing horizons. Capital investment in the DJ Basin in 2018 was $39.7 million and focused on the drilling and completion of four wells, three of which targeted the Codell formation and one the Niobrara formation. Production for the fourth quarter of 2018 was approximately 1,203 BOE/day, or approximately 631 BOE/day on an annual average basis.

The Corporation also has working interests in Sleeping Giant, a mature, light oil property located in the Elm Coulee Field in Richland County, Montana. Sleeping Giant produced approximately 3,315 BOE/day on average from the Bakken formation in 2018.

Overall, the Corporation's U.S. crude oil properties produced an average of approximately 43,605 BOE/day in 2018, up 36% from 2017 due to higher capital spending in North Dakota. On a BOE basis, this represents 47% of the Corporation's 2018 average daily production.

Approximately 35.1 MMBOE of proved plus probable reserves were added at Fort Berthold during 2018, including technical revisions and economic factors. After adjusting for 2018 production of 14.5 MMBOE, total proved plus probable reserves associated with this property as at December 31, 2018 were 191.1 MMBOE, 12% higher than at December 31, 2017.

The Corporation had 206.3 MMBOE of proved plus probable reserves associated with its U.S. crude oil assets at December 31, 2018, representing approximately 48% of its total proved plus probable reserves.

The Corporation has entered into long-term agreements for the gathering, dehydration, processing, compression and transportation of the Corporation's share of crude oil, natural gas and NGL production from its North Dakota and Montana properties. These agreements are intended to provide the Corporation with cost certainty, and access to the U.S. Gulf Coast, where it can further access export crude oil markets. See "*Marketing Arrangements and Forward Contracts"* for further information.

U.S. Natural Gas Properties

OVERVIEW

The Corporation's U.S. natural gas properties consist entirely of its non-operated Marcellus shale gas interests located in northeastern Pennsylvania, where the Corporation holds an interest in about 34,500 net acres. The Corporation's Marcellus shale gas production averaged 207,993 Mcf/day in 2018, representing approximately 37% of the Corporation's total average daily production.

In 2018, approximately $66.2 million was invested in the Corporation's Marcellus interests. The Corporation participated in the drilling of a total of 8.3 net wells, a total of 6.7 net wells were brought on-stream, and 6.0 net wells were waiting on completion or tie-in.

Proved plus probable Marcellus shale gas reserves were 1,029.2 Bcf as at December 31, 2018, an increase of 111.5 Bcf from 2017, and represented approximately 40% of the Corporation's total proved plus probable reserves.

The Corporation has entered into long-term agreements for the gathering, dehydration, compression and transportation of the Corporation's share of production from its Marcellus properties. These agreements are intended to provide the Corporation with cost certainty and access to the northeastern United States and broader U.S. natural gas markets through connections with major interstate pipelines. See "*Marketing Arrangements and Forward Contracts"* for further information.

Canadian Crude Oil Properties

OVERVIEW

Production from the Corporation's Canadian crude oil properties comes primarily from mature, low decline assets under waterflood and EOR techniques. Primary waterfloods inject water into the formation using injection wells to supplement 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 more predictable production profile and more stable declines, as well as higher recovery of reserves. Infill drilling, well injection optimization and EOR techniques are effective methods of improving recovery of reserves even further. These properties have associated crude oil production facilities for emulsion treatment and injection or water disposal.

The Canadian crude oil properties provide a stable production base and cash flow to support the Corporation's investment in growth plays, as well as its dividend. Total Canadian crude oil properties production averaged 9,897 BOE/day during 2018, or 11% of the Corporation's total average daily production. Capital investment in the Canadian crude oil properties was focused on its waterflood assets in Alberta, including water injection and optimization activities at Ante Creek and drilling activity in Medicine Hat, as well as drilling and on-streams in southeast Saskatchewan. On a production basis, the Corporation operated approximately 97% of its Canadian crude oil properties.

In 2018, the Corporation invested approximately $46.3 million in its Canadian crude oil properties, which was directed to drilling, completions, waterflood optimization and advancement, along with facility enhancements to support future activities. The Corporation drilled and completed 4.8 net crude oil wells and 2.2 net water injection wells in its Canadian crude oil properties during 2018.

Effectively all of the 41.8 MMBOE, or approximately 10% of the Corporation's total proved plus probable reserves on a BOE basis are associated with Canadian crude oil properties using waterflood or EOR techniques at December 31, 2018.

Canadian Natural Gas Properties

OVERVIEW

The Corporation's primary Canadian natural gas properties are located in Alberta and British Columbia. During 2018, production from the Corporation's Canadian natural gas properties averaged 34,326 Mcf/day. The Corporation's largest producing Canadian natural gas property in 2018 was Tommy Lakes, located in British Columbia.

The Corporation spent approximately $7 million of capital on its non-operated Canadian natural gas assets at Ferrier and Willesden Green during 2018.

Proved plus probable reserves for Canadian natural gas properties totaled 48.3 BcfGE as at December 31, 2018, representing approximately 2% of the Corporation's total proved plus probable reserves on a BOE basis.

QUARTERLY PRODUCTION HISTORY

The following table sets forth the Corporation's average daily production volumes, on a company interest basis, by product type, for each fiscal quarter in 2018 and for the entire year, separately for production in Canada and the United States, and in total.

	Year Ended December 31, 2018				
Country and Product Type	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States					
Light and medium oil (bbls/day)	-	-	-	-	**-**
Heavy oil (bbls/day)	-	-	-	-	**-**
Tight oil (bbls/day)	27,930	36,030	39,697	40,731	**36,142**
Total crude oil (bbls/day)	27,930	36,030	39,697	40,731	**36,142**
Natural gas liquids (bbls/day)	2,838	3,753	3,561	3,527	**3,422**
Total liquids (bbls/day)	30,768	39,783	43,258	44,258	**39,564**
Conventional natural gas (Mcf/day)	-	-	-	-	**-**
Shale gas (Mcf/day)	228,178	227,844	236,105	237,096	**232,340**
Total United States (BOE/day)	**68,798**	**77,757**	**82,608**	**83,774**	**78,287**
Canada					
Light and medium oil (bbls/day)	4,255	4,332	4,266	4,293	**4,287**
Heavy oil (bbls/day)	5,258	4,880	4,904	4,944	**4,995**
Tight oil (bbls/day)	-	-	-	-	**-**
Total crude oil (bbls/day)	9,513	9,212	9,170	9,237	**9,282**
Natural gas liquids (bbls/day)	1,247	1,055	1,002	956	**1,064**
Total liquids (bbls/day)	10,760	10,267	10,172	10,193	**10,346**
Conventional natural gas (Mcf/day)	32,691	28,750	24,226	23,105	**27,159**
Shale gas (Mcf/day)	441	401	260	252	**338**
Total Canada (BOE/day)	**16,282**	**15,126**	**14,253**	**14,086**	**14,929**
Total					
Light and medium oil (bbls/day)	4,255	4,332	4,266	4,293	**4,287**
Heavy oil (bbls/day)	5,258	4,880	4,904	4,944	**4,995**
Tight oil (bbls/day)	27,930	36,030	39,697	40,731	**36,142**
Total crude oil (bbls/day)	37,443	45,242	48,867	49,968	**45,424**
Natural gas liquids (bbls/day)	4,085	4,808	4,563	4,483	**4,486**
Total liquids (bbls/day)	41,528	50,050	53,430	54,451	**49,910**
Conventional natural gas (Mcf/day)	32,691	28,750	24,226	23,105	**27,159**
Shale gas (Mcf/day)	228,619	228,245	236,365	237,348	**232,678**
Total (BOE/day)	**85,080**	**92,883**	**96,861**	**97,860**	**93,216**

QUARTERLY NETBACK HISTORY

The following tables set forth the Corporation's average netbacks received for each fiscal quarter in 2018 and for the entire year, separately for production in Canada and the United States. Netbacks are calculated on the basis of prices received, which are net of transportation costs but before the effects of commodity derivative instruments, less related royalties and production costs. For multiple product wells, 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, 2018				
Light and Medium Crude Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price[1]	$ 62.23	$ 73.59	$ 74.09	$ 43.66	**$ 63.38**
Transportation	(1.82)	(1.76)	(1.70)	(1.64)	**(1.73)**
Royalties[2]	(15.44)	(16.77)	(18.34)	(10.94)	**(15.36)**
Production costs[3]	(14.36)	(10.82)	(17.17)	(13.82)	**(14.04)**
Netback	$ 30.61	$ 44.24	$ 36.88	$ 17.26	**$ 32.25**

	Year Ended December 31, 2018				
Heavy Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price[1]	$ 45.21	$ 60.36	$ 64.79	$ 25.16	**$ 48.75**
Transportation	(1.71)	(2.05)	(1.72)	(1.60)	**(1.77)**
Royalties[2]	(8.73)	(11.07)	(16.08)	(4.06)	**(9.95)**
Production costs[3]	(11.82)	(15.91)	(15.18)	(16.78)	**(14.89)**
Netback	$ 22.95	$ 31.33	$ 31.81	$ 2.72	**$ 22.14**

	Year Ended December 31, 2018				
Tight Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States					
Sales price[1]	$ 75.41	$ 83.41	$ 87.42	$ 71.07	**$ 79.49**
Transportation	(2.42)	(2.83)	(3.01)	(3.06)	**(2.87)**
Royalties[2]	(21.01)	(23.31)	(24.25)	(20.33)	**(22.28)**
Production costs[3]	(12.61)	(12.82)	(10.79)	(11.42)	**(11.82)**
Netback	$ 39.37	$ 44.45	$ 49.37	$ 36.26	**$ 42.52**

	Year Ended December 31, 2018				
Natural Gas Liquids ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States					
Sales price[1]	$ 20.66	$ 27.18	$ 20.47	$ 23.20	**$ 23.05**
Transportation	(1.82)	(2.00)	(1.90)	(1.85)	**(1.90)**
Royalties[2]	(3.34)	(5.15)	(3.59)	(4.68)	**(4.25)**
Production costs[3]	-	-	-	-	**-**
Netback	$ 15.50	$ 20.03	$ 14.98	$ 16.67	**$ 16.90**
Canada					
Sales price[1]	$ 45.11	$ 50.20	$ 45.44	$ 39.69	**$ 45.22**
Transportation	(1.27)	(1.97)	(1.35)	(1.37)	**(1.48)**
Royalties[2]	(8.93)	(10.91)	(7.86)	(8.10)	**(8.99)**
Production costs[3]	-	-	-	-	**-**
Netback	$ 34.91	$ 37.32	$ 36.23	$ 30.22	**$ 34.75**

Conventional Natural Gas ($ per Mcf)	Year Ended December 31, 2018 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Canada					
Sales price[1]	$ 3.12	$ 2.09	$ 2.80	$ 3.76	**$ 2.91**
Transportation	(0.46)	(0.39)	(0.60)	(0.51)	**(0.48)**
Royalties[2]	0.12	0.41	0.25	0.49	**0.30**
Production costs[3]	(3.19)	(2.37)	(2.48)	(2.19)	**(2.60)**
Netback	$ (0.41)	$ (0.26)	$ (0.03)	$ 1.55	**$ 0.13**

Shale Gas ($ per Mcf)	Year Ended December 31, 2018 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
United States					
Sales price[1]	$ 3.56	$ 2.76	$ 3.27	$ 4.33	**$ 3.49**
Transportation	(0.84)	(0.84)	(0.85)	(0.86)	**(0.85)**
Royalties[2]	(0.76)	(0.60)	(0.69)	(0.95)	**(0.75)**
Production costs[3]	(0.07)	(0.06)	(0.10)	(0.11)	**(0.09)**
Netback	$ 1.89	$ 1.26	$ 1.63	$ 2.41	**$ 1.80**
Canada					
Sales price[1]	$ 2.58	$ 1.14	$ 1.59	$ 2.16	**$ 1.88**
Royalties[2]	(0.46)	(0.39)	(0.60)	(0.51)	**(0.48)**
Transportation	(0.11)	(0.07)	(0.07)	(0.11)	**(0.09)**
Production costs[3]	(1.56)	(2.13)	(2.49)	(3.06)	**(2.19)**
Netback	$ 0.45	$ (1.45)	$ (1.57)	$ (1.52)	**$ (0.88)**

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

TAX HORIZON

The Corporation is subject to standard applicable corporate income taxes. Based on existing tax legislation, the Corporation's available tax pools, expected capital expenditures and forecasted net income, the Corporation does not anticipate paying material cash taxes in either Canada or the United States until 2021. These expectations may vary depending on numerous factors, including fluctuations in commodity prices, the Corporation's capital spending, changes in tax laws, and the nature and timing of the Corporation's acquisitions and divestments. As a result, the Corporation emphasizes that it is difficult to give guidance on future taxability as it operates within an industry that constantly changes. See "*Risk Factors – Changes in laws or free trade agreements, including those affecting tax, royalties and other financial and trade matters, and interpretations of those laws and trade agreements, may adversely affect the Corporation and its securityholders"*.

For additional information, see Notes 2(i) and 12 to the Financial Statements and the information under the heading "Income Taxes" in the Corporation's MD&A, which can be found on its SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

MARKETING ARRANGEMENTS AND FORWARD CONTRACTS

Crude Oil and NGLs

The Corporation's crude oil and NGLs production is marketed to a diverse portfolio of intermediaries and end users, generally on 30-day continuously renewing contracts for crude oil in Canada, negotiated contracts ranging from 30 days up to two years for crude oil in the U.S., and yearly contracts for NGLs in Canada, where terms fluctuate with the monthly spot markets. NGLs contracts in the U.S. are linked to processing arrangements with pricing linked to the monthly spot markets. The Corporation received an average price (before transportation costs, royalties, and the effects of commodity derivative instruments) of $74.59/bbl for its crude oil and $28.31/bbl for its NGLs for the year ended December 31, 2018, compared to $58.69/bbl for its crude oil and $30.01/bbl for its NGLs for the year ended December 31, 2017.

In the United States, the Corporation transports its U.S. crude oil production to its buyers by pipeline and/or truck, and may occasionally sell a portion to buyers who may utilize rail transportation (after title is transferred into the buyer's name). In 2018, the Corporation received an average price differential for its U.S. Bakken crude oil of US$3.78/bbl below WTI, compared to an average of US$3.72/bbl below WTI in 2017. The Corporation has firm sales contracts in place for approximately 21,000 bbls/day, on average, during 2019 for its U.S. oil production, which includes an average of 16,000 bbls/day of physical sales with a fixed differential of US$3.00/bbl below WTI. The Corporation also expects to transport a portion of its North Dakota crude oil production to the U.S. Gulf Coast, where it can further access export crude oil markets. The Corporation's NGLs associated with its U.S. crude oil production volumes are marketed on its behalf by midstream companies in North Dakota and Montana.

In Canada, the Corporation typically transports its Canadian crude oil production to its buyers by pipeline and/or truck. The Corporation may occasionally sell a portion of its crude oil production to buyers who may use rail transportation (after title is transferred into the buyer's name). The Corporation has firm transportation capacity for approximately 3,200 BOE/day of crude oil and natural gas liquids production in 2019, decreasing to approximately 1,400 BOE/day on average from 2020 to 2027. Additionally, the Corporation has contracted firm NGLs fractionation agreements for 1,100 BOE/day through 2027.

Natural Gas

In marketing its natural gas production, the Corporation strives for a mix of contracts and customers. In 2018, 80% of the Corporation's natural gas production originated from its non-operated Marcellus interest in northeast Pennsylvania. Pipeline egress out of the Marcellus region continued to come on-line during 2018. At times the Corporation curtailed natural gas production due to low regional spot pricing due to third party pipeline maintenance. See "*Risk Factors – Lack of adequately developed infrastructure, and the impact of special interest groups on such development, may result in a decline in the Corporation's ability to market its oil and natural gas production*". The Corporation delivered approximately 43% of its Marcellus production in 2018 onto the Transco Leidy Pipeline, with most of the remaining volumes delivered onto the Tennessee Gas Pipeline 300 Line in Pennsylvania. A portion was then transported to the Kentucky/Tennessee border. The Corporation has firm "must-take" sales contracts for up to 65 MMcf/day of natural gas production in the Marcellus for terms of up to seven years with buyers who hold pipeline capacity on these and other pipelines in the region. The Corporation also has firm transportation agreements to transport gas within and out of the region for approximately 66 MMcf/day, with terms ending between 2020 and 2036. The Corporation holds firm transportation capacity for 30 MMcf/day for five years on the PennEast Pipeline project. The Federal Energy Regulatory Commission approved the project through the issuance of a certificate of public convenience and necessity in January 2018. The expected in-service date was revised due to state-level regulatory delays. Pending final state-level regulatory approvals and construction schedules, the in-service date is now expected to be in 2020.

The average price received by the Corporation (before transportation, royalties, and the effects of commodity derivative instruments) for its natural gas in 2018 was $3.42/Mcf compared to $3.21/Mcf for the year ended December 31, 2017. The Corporation received an average price differential for its U.S. Marcellus shale gas production of US$0.43/Mcf below NYMEX prices. Approximately 9% of the Corporation's natural gas production was associated natural gas production from its crude oil operations in North Dakota and Montana. The Corporation does not market these volumes directly, as they are marketed on Enerplus' behalf by midstream companies.

In Canada, the Corporation sells its natural gas production at a mix of fixed and floating prices for a variety of terms ranging from spot sales to one year or longer. The Corporation's monthly sales portfolio reflected a mix of the daily and monthly market indices. The Corporation sold the majority of its Canadian natural gas production under fixed AECO-NYMEX basis differential contracts, benefiting the Corporation's Canadian natural gas differential, which averaged US$0.81/Mcf below NYMEX in 2018. Approximately 11% of the Corporation's total natural gas production originated in Canada in 2018 and received an average price (before transportation, royalties, and the effects of commodity derivative instruments), of $2.90/Mcf during the year. At December 31, 2018, the Corporation held firm service natural gas transportation contracts for its natural gas production in Canada for 2019 totalling 48.7 MMcf/day.

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 Notes 14(b) and 14(c)(i) to the Financial Statements and under the heading "*Results of Operations – Price Risk Management*" in the Corporation's MD&A, each of which is available through the internet on the Corporation's website at www.enerplus.com, on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

Oil and Natural Gas Reserves

SUMMARY OF RESERVES

All of the Corporation's reserves, including its U.S. reserves, have been evaluated in accordance with NI 51-101. Independent reserves evaluations have been conducted on properties comprising approximately 95% of the net present value (discounted at 10%, before tax, using forecast prices and costs) of the Corporation's total proved plus probable reserves.

McDaniel, an independent petroleum consulting firm based in Calgary, Alberta, has evaluated properties which comprise approximately 70% of the net present value (discounted at 10%, before tax, using forecast prices and costs) of the Corporation's proved plus probable reserves located in Canada and all of the Corporation's reserves associated with the Corporation's properties located in North Dakota, Montana and Colorado. McDaniel used the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2019 to prepare its report. The Corporation has evaluated the remaining 30% of the net present value of its Canadian properties using similar evaluation parameters, including the same forecast price and inflation rate assumptions utilized by McDaniel. McDaniel has reviewed the Corporation's internal evaluation of these properties.

NSAI, independent petroleum consultants based in Dallas, Texas, has evaluated all of the Corporation's reserves associated with the Corporation's properties in Pennsylvania. For consistency in the Corporation's reserves reporting, NSAI used the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2019 to prepare its report.

The Corporation used the average of the forecast exchange rates of GLJ, McDaniel and Sproule, set forth below, to convert U.S. dollar amounts in both the McDaniel and NSAI Reports to Canadian dollar amounts for presentation in this Annual Information Form.

The following sections and tables summarize, as at December 31, 2018, the Corporation's crude oil, NGLs and natural 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 reserves 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, 2017 to December 31, 2018, see "*– Reconciliation of Reserves*" below.

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

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

It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained, and variances could be material. The reserves estimates of the Corporation's crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Presentation of Oil and Gas Reserves, Contingent 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, 2018, using forecast price and cost cases.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)

As of December 31, 2018

	OIL AND NATURAL GAS RESERVES													
RESERVES	Light & Medium Oil		Heavy Oil		Tight Oil		Natural Gas Liquids		Conventional Natural Gas		Shale Gas		Total	
CATEGORY	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)
Proved Developed Producing														
Canada	9,062	7,514	17,969	15,506	-	-	1,178	1,066	28,707	29,245	1,059	1,006	33,170	29,127
United States	-	-	-	-	58,284	46,815	7,265	5,808	-	-	590,831	474,628	164,020	131,729
Total	**9,062**	**7,514**	**17,969**	**15,506**	**58,284**	**46,815**	**8,443**	**6,875**	**28,707**	**29,245**	**591,890**	**475,633**	**197,191**	**160,856**
Proved Developed Non-Producing														
Canada	15	14	135	124	-	-	91	65	2,213	2,081	-	-	609	550
United States	-	-	-	-	921	751	47	38	-	-	3,748	3,039	1,593	1,295
Total	**15**	**14**	**135**	**124**	**921**	**751**	**138**	**103**	**2,213**	**2,081**	**3,748**	**3,039**	**2,202**	**1,845**
Proved Undeveloped														
Canada	560	489	3,077	2,560	-	-	1	1	88	73	-	-	3,653	3,062
United States	-	-	-	-	47,325	37,881	5,201	4,165	-	-	253,426	200,992	94,763	75,544
Total	**560**	**489**	**3,077**	**2,560**	**47,325**	**37,881**	**5,202**	**4,166**	**88**	**73**	**253,426**	**200,992**	**98,416**	**78,606**
Total Proved														
Canada	9,637	8,017	21,181	18,189	-	-	1,270	1,132	31,007	31,399	1,059	1,006	37,432	32,740
United States	-	-	-	-	106,530	85,447	12,513	10,011	-	-	848,004	678,658	260,376	208,567
Total	**9,637**	**8,017**	**21,181**	**18,189**	**106,530**	**85,447**	**13,783**	**11,143**	**31,007**	**31,399**	**849,063**	**679,664**	**297,809**	**241,307**
Probable														
Canada	3,024	2,387	7,215	5,985	-	-	452	409	10,129	10,168	215	204	12,414	10,510
United States	-	-	-	-	60,631	48,509	6,825	5,456	-	-	300,234	238,310	117,495	93,684
Total	**3,024**	**2,387**	**7,215**	**5,985**	**60,631**	**48,509**	**7,277**	**5,865**	**10,129**	**10,168**	**300,449**	**238,514**	**129,909**	**104,194**
Total Proved Plus Probable														
Canada	12,660	10,404	28,395	24,174	-	-	1,723	1,541	41,137	41,567	1,274	1,210	49,847	43,249
United States	-	-	-	-	167,160	133,956	19,338	15,467	-	-	1,148,238	916,968	377,871	302,251
Total	**12,660**	**10,404**	**28,395**	**24,174**	**167,160**	**133,956**	**21,060**	**17,008**	**41,137**	**41,567**	**1,149,511**	**918,178**	**427,718**	**345,501**

Summary of Net Present Value of Future Net Revenue Attributable to Oil and Gas Reserves (Forecast Prices and Costs)

As of December 31, 2018

	NET PRESENT VALUE OF FUTURE NET REVENUE DISCOUNTED AT (%/Year)										
	Before Deducting Income Taxes					After Deducting Income Taxes[1]					Unit
RESERVES CATEGORY	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	Value[2]
					(in $ millions)						$/BOE
Proved Developed Producing											
Canada	907	665	522	429	365	907	665	522	429	365	$17.90
United States	3,600	2,592	2,046	1,711	1,484	3,101	2,301	1,855	1,575	1,383	$15.53
Total	**4,507**	**3,257**	**2,568**	**2,140**	**1,849**	**4,008**	**2,966**	**2,376**	**2,005**	**1,748**	**$15.96**
Proved Developed Non-Producing											
Canada	(12)	(11)	(10)	(10)	(9)	(12)	(11)	(10)	(10)	(9)	($18.93)
United States	29	23	19	16	13	22	17	14	12	10	$14.47
Total	**17**	**12**	**8**	**6**	**4**	**10**	**6**	**4**	**2**	**1**	**$4.51**
Proved Undeveloped											
Canada	92	63	43	30	20	70	55	40	29	20	$14.18
United States	1,623	995	652	437	291	1,179	717	460	298	187	$8.63
Total	**1,714**	**1,057**	**695**	**467**	**311**	**1,249**	**772**	**500**	**326**	**207**	**$8.84**
Total Proved											
Canada	987	716	555	449	377	965	708	551	448	376	$16.94
United States	5,251	3,610	2,717	2,163	1,788	4,301	3,035	2,329	1,885	1,581	$13.03
Total	**6,238**	**4,326**	**3,271**	**2,613**	**2,165**	**5,266**	**3,743**	**2,880**	**2,333**	**1,956**	**$13.56**
Probable											
Canada	437	253	166	119	90	319	195	136	102	80	$15.82
United States	3,438	1,827	1,145	792	582	2,519	1,338	835	576	423	$12.22
Total	**3,875**	**2,080**	**1,311**	**911**	**672**	**2,838**	**1,533**	**971**	**678**	**503**	**$12.58**
Total Proved Plus Probable											
Canada	1,423	969	721	568	467	1,284	903	687	550	456	$16.67
United States	8,690	5,436	3,861	2,955	2,370	6,820	4,373	3,165	2,462	2,004	$12.78
Total	**10,113**	**6,405**	**4,582**	**3,523**	**2,837**	**8,105**	**5,277**	**3,851**	**3,011**	**2,460**	**$13.26**

Notes:

(1) Income tax calculations are based on the forecast cash flows of reserves volumes only, taking into consideration the forecast capital required to develop the reserves, and having regard for remaining corporate tax pools at the effective date, applicable deductions and appropriate federal, provincial and state tax rates.

(2) 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 is based on the following average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2019 (utilized by McDaniel, NSAI and by the Corporation in its internal evaluations for consistency in the Corporation's reserves reporting), and the following inflation and exchange rate assumptions:

	CRUDE OIL				**NATURAL GAS**		**NATURAL GAS LIQUIDS Edmonton Par Price**				
Year	**WTI(1)**	**Edmonton Light(2)**	**Alberta Heavy(3)**	**Sask Cromer Medium(4)**	**Alberta AECO Spot Prices**	**U.S. Henry Hub Gas Price**	**Propane**	**Butanes**	**Condensate & Natural Gasolines**	**Inflation Rate**	**Exchange Rate**
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/MMbtu)	($US/MMbtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	(%/year)	($US/$Cdn)
2019	58.58	67.30	43.92	63.99	1.88	3.00	26.13	27.32	70.10	-	0.757
2020	64.60	75.84	52.76	71.38	2.31	3.13	31.27	41.10	79.21	2.0	0.782
2021	68.20	80.17	59.10	75.14	2.74	3.33	34.58	49.28	83.33	2.0	0.797
2022	71.00	83.22	61.60	78.06	3.05	3.51	37.25	55.65	86.20	2.0	0.803
2023	72.81	85.34	63.39	80.06	3.21	3.62	38.73	57.92	88.16	2.0	0.807
2024	74.59	87.33	65.14	81.96	3.31	3.70	39.75	59.27	90.20	2.0	0.808
2025	76.42	89.50	66.99	84.02	3.39	3.77	40.76	60.77	92.43	2.0	0.808
2026	78.40	91.89	69.06	86.29	3.46	3.85	41.93	62.37	94.87	2.0	0.808
2027	79.98	93.76	70.60	88.08	3.54	3.92	42.84	63.65	96.80	2.0	0.808
2028	81.59	95.68	72.17	89.90	3.62	4.01	43.80	64.97	98.79	2.0	0.808
2029	83.22	97.60	73.62	91.69	3.69	4.09	44.68	66.27	100.76	2.0	0.808
2030	84.89	99.55	75.09	93.53	3.77	4.17	45.57	67.60	102.78	2.0	0.808
2031	86.58	101.54	76.59	95.40	3.84	4.25	46.48	68.95	104.83	2.0	0.808
2032	88.31	103.57	78.12	97.31	3.92	4.34	47.41	70.33	106.93	2.0	0.808
2033	90.08	105.64	79.68	99.25	4.00	4.42	48.36	71.74	109.07	2.0	0.808
Thereafter	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	0.808

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

In 2018, the Corporation received a weighted average price (before transportation costs, royalties, and the effects of commodity derivative instruments) of $74.59/bbl for crude oil, $28.31/bbl for natural gas liquids and $3.42/Mcf for natural gas.

UNDISCOUNTED FUTURE NET REVENUE BY RESERVES CATEGORY

The undiscounted total future net revenue by reserves category as of December 31, 2018, using forecast prices and costs, is set forth below (columns or rows may not add due to rounding):

RESERVES CATEGORY	**Revenue**	**Royalties(1)**	**Operating Costs**	**Development Costs**	**Abandonment and Reclamation Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes(2)**
				(in $ millions)				
Proved Reserves								
Canada	2,389	365	878	120	40	987	21	965
United States	12,583	3,255	2,634	1,228	215	5,251	950	4,301
Total	14,973	3,619	3,512	1,348	255	6,238	972	5,266
Proved Plus Probable Reserves								
Canada	3,322	531	1,188	135	44	1,423	139	1,284
United States	20,114	5,263	4,001	1,887	274	8,690	1,869	6,820
Total	23,436	5,794	5,190	2,022	318	10,113	2,008	8,105

Notes:
(1) Royalties include any net profits interests paid, as well as the Saskatchewan Corporation Capital Tax Surcharge.
(2) Income tax calculations are based on the forecast cash flows of reserves volumes only, taking into consideration the forecast capital required to develop the reserves, and having regard for remaining corporate tax pools at the effective date, applicable deductions and appropriate federal, provincial and state tax rates.

NET PRESENT VALUE OF FUTURE NET REVENUE BY RESERVES CATEGORY AND PRODUCT TYPE

The net present value of future net revenue before income taxes by reserves category and product type as of December 31, 2018, using forecast prices and costs and discounted at 10% per year, is set forth below:

RESERVES CATEGORY	PRODUCT TYPE	Future Net Revenue Before Income Taxes (Discounted at 10%)	Unit Value[1]
		(in $ millions)	($/bbl; $/Mcf)
Canada			
Proved Reserves	Light and Medium Oil (including solution gas and by-products)[2]	184,404	23.08
	Heavy Oil (including solution gas and by-products) [2]	335,429	18.44
	Tight Oil[2]	n/a	n/a
	Conventional Natural Gas (including by-products)[3]	31,881	1.20
	Shale Gas[3]	2,797	2.78
	Total	**554,511**	
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and by-products)[2]	242,656	23.40
	Heavy Oil (including solution gas and by-products) [2]	434,184	17.96
	Tight Oil[2]	n/a	n/a
	Conventional Natural Gas (including by-products)[3]	40,697	1.15
	Shale Gas[3]	3,268	2.70
	Total	**720,805**	
United States			
Proved Reserves	Light and Medium Oil (including solution gas and by-products) [2]	n/a	n/a
	Heavy Oil (including solution gas and by-products) [2]	n/a	n/a
	Tight Oil[2]	2,013,667	23.57
	Conventional Natural Gas (including by-products) [3]	n/a	n/a
	Shale Gas[4]	702,959	1.15
	Total	**2,716,626**	
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and by-products) [2]	n/a	n/a
	Heavy Oil (including solution gas and by-products) [2]	n/a	n/a
	Tight Oil[2]	3,011,904	22.48
	Conventional Natural Gas (including by-products) [3]	n/a	n/a
	Shale Gas[4]	849,393	1.03
	Total	**3,861,298**	
Total			
Proved Reserves	Light and Medium Oil (including solution gas and by-products) [2]	184,404	
	Heavy Oil (including solution gas and by-products) [2]	335,429	
	Tight Oil[2]	2,013,667	
	Conventional Natural Gas (including by-products) [3]	31,881	
	Shale Gas[3][4]	705,756	
	Total	**3,271,137**	
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and by-products) [2]	242,656	
	Heavy Oil (including solution gas and by-products) [2]	434,184	
	Tight Oil[2]	3,011,904	
	Conventional Natural Gas (including by-products) [3]	40,697	
	Shale Gas[3][4]	852,661	
	Total	**4,582,103**	

Notes:

(1) Unit values are calculated using the 10% discounted rate divided by the major product type net reserves for each group.
(2) Including net present value of solution gas and other by-products.
(3) Including net present value of by-products, but excluding solution gas and by-products from oil wells.
(4) No by-product oil or NGLs are associated with U.S. shale gas.

ESTIMATED PRODUCTION FOR GROSS RESERVES ESTIMATES

The volume of total production for the Corporation estimated for 2019 in preparing the estimates of gross proved reserves and gross probable reserves is set forth below. Actual 2019 production (including from the Fort Berthold and Marcellus properties in the separate tables below) may vary from the estimates provided by McDaniel and NSAI as the Corporation's actual development programs, timing and priorities may differ from the forecast of development by McDaniel and NSAI. Columns may not add due to rounding.

	Gross Proved Reserves							
	Canada				United States			
Product Type	Estimated 2019 Aggregate Production		Estimated 2019 Average Daily Production		Estimated 2019 Aggregate Production		Estimated 2019 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	1,476	Mbbls	4,044	bbls/day	-	Mbbls	-	bbls/day
Heavy Oil	1,873	Mbbls	5,132	bbls/day	-	Mbbls	-	bbls/day
Tight Oil	-	Mbbls	-	bbls/day	15,670	Mbbls	42,933	bbls/day
Total Crude Oil	3,349	Mbbls	9,176	bbls/day	15,670	Mbbls	42,933	bbls/day
Natural Gas Liquids	225	Mbbls	618	bbls/day	1,719	Mbbls	4,708	bbls/day
Total Liquids	3,575	Mbbls	9,793	bbls/day	17,389	Mbbls	47,641	bbls/day
Conventional Natural Gas	6,993	MMcf	19,159	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	119	MMcf	325	Mcf/day	80,217	MMcf	219,773	Mcf/day
Total	4,760	MBOE	13,041	BOE/day	30,758	MBOE	84,270	BOE/day

	Gross Probable Reserves							
	Canada				United States			
Product Type	Estimated 2019 Aggregate Production		Estimated 2019 Average Daily Production		Estimated 2019 Aggregate Production		Estimated 2019 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	92	Mbbls	251	bbls/day	-	Mbbls	-	bbls/day
Heavy Oil	59	Mbbls	162	bbls/day	-	Mbbls	-	bbls/day
Tight Oil	-	Mbbls	-	bbls/day	1,081	Mbbls	2,961	bbls/day
Total Crude Oil	151	Mbbls	413	bbls/day	1,081	Mbbls	2,961	bbls/day
Natural Gas Liquids	20	Mbbls	55	bbls/day	111	Mbbls	304	bbls/day
Total Liquids	171	Mbbls	468	bbls/day	1,192	Mbbls	3,265	bbls/day
Conventional Natural Gas	517	MMcf	1,417	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	2	MMcf	5	Mcf/day	5,963	MMcf	16,338	Mcf/day
Total	257	MBOE	705	BOE/day	2,186	MBOE	5,988	BOE/day

The tables below set forth McDaniel's and NSAI's estimated 2019 production for the Corporation's Fort Berthold property located in North Dakota, United States, and the Marcellus property, located in Pennsylvania, United States, respectively, as each field is estimated to account for more than 20% of the above estimate of the Corporation's 2019 production.

	Gross Proved Reserves							
	Fort Berthold				Marcellus			
Product Type	Estimated 2019 Aggregate Production		Estimated 2019 Average Daily Production		Estimated 2019 Aggregate Production		Estimated 2019 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	-	Mbbls	-	bbls/day	-	Mbbls	-	bbls/day
Heavy Oil	-	Mbbls	-	bbls/day	-	Mbbls	-	bbls/day
Tight Oil	14,632	Mbbls	40,087	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	14,632	Mbbls	40,087	bbls/day	-	Mbbls	-	bbls/day
Natural Gas Liquids	1,698	Mbbls	4,651	bbls/day	-	Mbbls	-	bbls/day
Total Liquids	16,329	Mbbls	44,738	bbls/day	-	Mbbls	-	bbls/day
Conventional Natural Gas	-	MMcf	-	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	8,488	MMcf	23,254	Mcf/day	69,816	MMcf	191,276	Mcf/day
Total	17,744	MBOE	48,614	BOE/day	11,636	MBOE	31,879	BOE/day

	Gross Probable Reserves							
	Fort Berthold				Marcellus			
Product Type	Estimated 2019 Aggregate Production		Estimated 2019 Average Daily Production		Estimated 2019 Aggregate Production		Estimated 2019 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	-	Mbbls	-	bbls/day	-	Mbbls	-	bbls/day
Heavy Oil	-	Mbbls	-	bbls/day	-	Mbbls	-	bbls/day
Tight Oil	793	Mbbls	2,174	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	793	Mbbls	2,174	bbls/day	-	Mbbls	-	bbls/day
Natural Gas Liquids	84	Mbbls	230	bbls/day	-	Mbbls	-	bbls/day
Total Liquids	877	Mbbls	2,404	bbls/day	-	Mbbls	-	bbls/day
Conventional Natural Gas	-	MMcf	-	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	420	MMcf	1,149	Mcf/day	5,442	MMcf	14,910	Mcf/day
Total	947	MBOE	2,595	BOE/day	907	MBOE	2,485	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 cash, internally generated cash flow and/or debt. The Corporation does not anticipate that the cost of obtaining the funds required for these development activities will have a material effect on the Corporation's disclosed oil and gas reserves or future net revenue attributable to those reserves. For additional information, see "*Business of the Corporation – Capital Expenditures and Costs Incurred*".

	CANADA				UNITED STATES			
	Proved Reserves		Proved Plus Probable Reserves		Proved Reserves		Proved Plus Probable Reserves	
Year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year
				(in $ millions)				
2019	43	41	43	41	613	591	671	647
2020	37	32	37	32	490	424	506	437
2021	11	9	19	15	95	76	505	397
2022	10	7	17	12	24	18	146	107
2023	8	5	7	5	5	3	58	38
2024	6	4	6	4	-	-	1	1
Remainder	5	3	6	3	-	-	-	-
Total	120	101	135	112	1,228	1,112	1,887	1,627

RECONCILIATION OF RESERVES

Overview

The Corporation's total gross proved plus probable reserves at December 31, 2018 were 427.7 MMBOE, an increase of approximately 8% from year-end 2017. The Corporation's gross proved plus probable crude oil and NGLs reserves were 229.3 MMBOE and represented approximately 54% of total proved plus probable gross reserves, up 8% from year-end 2017. The Corporation replaced approximately 194% of its 2018 gross production through its exploration and development program, adding approximately 65.7 MMBOE of proved plus probable reserves, including revisions and economic factors. Approximately 54% of the additions, including revisions and economic factors, were crude oil and NGLs, representing the replacement of 198% of the Corporation's 2018 crude oil and NGLs production. Of the Corporation’s approximately 65.7 MMBOE of proved plus probable additions, including revisions and economic factors, 35.1 MMBOE is attributed to the Fort Berthold property and 31.2 MMBOE (187.4 Bcf) to the Marcellus shale gas property.

The Corporation sold 1.9 MMBOE of proved plus probable reserves in 2018, the majority of which were associated with Canadian properties. Total proved plus probable conventional natural gas reserves decreased by approximately 47% from year-end 2017 as a result of these divestments and the truncation of reserves volumes in the Tommy Lakes asset in 2020.

The following tables reconcile the Corporation's gross crude oil and natural gas reserves from December 31, 2017 to December 31, 2018, by country and in total, using forecast prices and costs. Certain columns may not add due to rounding.

CANADIAN OIL AND GAS RESERVES

CANADA Factors	Light & Medium Oil Proved	Light & Medium Oil Probable	Light & Medium Oil Proved Plus Probable	Heavy Oil Proved	Heavy Oil Probable	Heavy Oil Proved Plus Probable	Tight Oil Proved	Tight Oil Probable	Tight Oil Proved Plus Probable	Natural Gas Liquids Proved	Natural Gas Liquids Probable	Natural Gas Liquids Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2017	8,890	2,719	11,609	22,552	7,635	30,187	-	-	-	1,935	831	2,767
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(2)	(1)	(3)	-	-	-	-	-	-	(70)	(35)	(105)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	1,501	1,150	2,651	500	1,023	1,522	-	-	-	42	20	61
Economic Factors	64	(109)	(45)	127	25	152	-	-	-	(82)	(87)	(169)
Technical Revisions	1,007	(735)	272	(437)	(1,468)	(1,906)	-	-	-	(231)	(277)	(508)
Production	(1,823)	-	(1,823)	(1,560)	-	(1,560)	-	-	-	(324)	-	(324)
December 31, 2018	**9,637**	**3,024**	**12,660**	**21,181**	**7,215**	**28,395**	**-**	**-**	**-**	**1,270**	**452**	**1,723**

CANADA Factors	Conventional Natural Gas Proved	Conventional Natural Gas Probable	Conventional Natural Gas Proved Plus Probable	Shale Gas Proved	Shale Gas Probable	Shale Gas Proved Plus Probable	Total Proved	Total Probable	Total Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2017	55,992	21,289	77,281	1,367	349	1,715	42,937	14,792	57,729
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(6,447)	(2,293)	(8,741)	-	-	-	(1,147)	(418)	(1,565)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	976	395	1,372	-	-	-	2,205	2,258	4,463
Economic Factors	(1,597)	(1,523)	(3,120)	(9)	1	(8)	(159)	(425)	(584)
Technical Revisions	(8,602)	(7,739)	(16,341)	(176)	(135)	(311)	(1,124)	(3,793)	(4,917)
Production	(9,314)	-	(9,314)	(123)	-	(123)	(5,280)	-	(5,280)
December 31, 2018	**31,007**	**10,129**	**41,137**	**1,059**	**215**	**1,274**	**37,432**	**12,414**	**49,847**

UNITED STATES OIL AND GAS RESERVES

UNITED STATES Factors	Light & Medium Oil Proved	Light & Medium Oil Probable	Light & Medium Oil Proved Plus Probable	Heavy Oil Proved	Heavy Oil Probable	Heavy Oil Proved Plus Probable	Tight Oil Proved	Tight Oil Probable	Tight Oil Proved Plus Probable	Natural Gas Liquids Proved	Natural Gas Liquids Probable	Natural Gas Liquids Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2017	-	-	-	-	-	-	91,101	58,125	149,227	11,065	6,921	17,985
Acquisitions	-	-	-	-	-	-	175	39	214	23	5	28
Dispositions	-	-	-	-	-	-	(239)	(65)	(305)	(25)	(7)	(32)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	21,485	13,675	35,160	2,251	1,377	3,628
Economic Factors	-	-	-	-	-	-	(84)	(71)	(155)	(17)	(8)	(26)
Technical Revisions	-	-	-	-	-	-	7,236	(11,073)	(3,836)	463	(1,462)	(999)
Production	-	-	-	-	-	-	(13,144)	-	(13,144)	(1,246)	-	(1,246)
December 31, 2018	**-**	**-**	**-**	**-**	**-**	**-**	**106,530**	**60,631**	**167,160**	**12,513**	**6,825**	**19,338**

UNITED STATES Factors	Conventional Natural Gas Proved	Conventional Natural Gas Probable	Conventional Natural Gas Proved Plus Probable	Shale Gas Proved	Shale Gas Probable	Shale Gas Proved Plus Probable	Total Proved	Total Probable	Total Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2017	-	-	-	801,651	233,393	1,035,045	235,775	103,945	339,719
Acquisitions	-	-	-	114	26	139	217	48	265
Dispositions	-	-	-	(126)	(37)	(162)	(286)	(78)	(364)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	77,554	70,598	148,152	36,661	26,819	63,480
Economic Factors	-	-	-	(1,232)	548	(683)	(306)	12	(294)
Technical Revisions	-	-	-	54,734	(4,295)	50,440	16,821	(13,251)	3,571
Production	-	-	-	(84,691)	-	(84,691)	(28,506)	-	(28,506)
December 31, 2018	**-**	**-**	**-**	**848,004**	**300,234**	**1,148,238**	**260,376**	**117,495**	**377,871**

TOTAL OIL AND GAS RESERVES

TOTAL Factors	Light & Medium Oil Proved	Light & Medium Oil Probable	Light & Medium Oil Proved Plus Probable	Heavy Oil Proved	Heavy Oil Probable	Heavy Oil Proved Plus Probable	Tight Oil Proved	Tight Oil Probable	Tight Oil Proved Plus Probable	Natural Gas Liquids Proved	Natural Gas Liquids Probable	Natural Gas Liquids Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2017	8,890	2,719	11,609	22,552	7,635	30,187	91,101	58,125	149,227	13,000	7,752	20,752
Acquisitions	-	-	-	-	-	-	175	39	214	23	5	28
Dispositions	(2)	(1)	(3)	-	-	-	(239)	(65)	(305)	(96)	(42)	(137)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	1,501	1,150	2,651	500	1,023	1,522	21,485	13,675	35,160	2,292	1,397	3,689
Economic Factors	64	(109)	(45)	127	25	152	(84)	(71)	(155)	(99)	(95)	(194)
Technical Revisions	1,007	(735)	272	(437)	(1,468)	(1,906)	7,236	(11,073)	(3,836)	232	(1,739)	(1,507)
Production	(1,823)	-	(1,823)	(1,560)	-	(1,560)	(13,144)	-	(13,144)	(1,570)	-	(1,570)
December 31, 2018	**9,637**	**3,024**	**12,660**	**21,181**	**7,215**	**28,395**	**106,530**	**60,631**	**167,160**	**13,783**	**7,277**	**21,060**

TOTAL Factors	Conventional Natural Gas Proved	Conventional Natural Gas Probable	Conventional Natural Gas Proved Plus Probable	Shale Gas Proved	Shale Gas Probable	Shale Gas Proved Plus Probable	Total Proved	Total Probable	Total Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2017	55,992	21,289	77,281	803,018	233,742	1,036,760	278,712	118,737	397,448
Acquisitions	-	-	-	114	26	139	217	48	265
Dispositions	(6,447)	(2,293)	(8,741)	(126)	(37)	(162)	(1,433)	(496)	(1,929)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	976	395	1,372	77,554	70,598	148,152	38,866	29,077	67,943
Economic Factors	(1,597)	(1,523)	(3,120)	(1,240)	549	(691)	(465)	(413)	(878)
Technical Revisions	(8,602)	(7,739)	(16,341)	54,558	(4,430)	50,129	15,697	(17,043)	(1,346)
Production	(9,314)	-	(9,314)	(84,814)	-	(84,814)	(33,785)	-	(33,785)
December 31, 2018	**31,007**	**10,129**	**41,137**	**849,063**	**300,449**	**1,149,511**	**297,809**	**129,909**	**427,718**

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

Year(1)	Crude Oil Light & Medium	Crude Oil Heavy	Crude Oil Tight	NGLs	Conventional Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
2016	100	-	3,492	391	-	6,080	4,996
2017	354	390	19,113	2,170	28	52,296	30,749
2018	450	500	17,345	1,725	-	64,895	30,835

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

Probable Undeveloped Reserves

Year(1)	Crude Oil Light & Medium	Crude Oil Heavy	Crude Oil Tight	NGLs	Conventional Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
2016	45	-	13,104	1,468	-	26,468	19,028
2017	163	165	14,891	1,645	12	37,251	23,075
2018	205	1,023	12,650	1,258	35	69,512	26,727

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 considers each of its undeveloped locations to be projects that have larger capital expenditures and, consistent with the COGE Handbook, has generally assigned development of or the commencement of significant capital spending on proved undeveloped locations to occur within three years (five years for resource plays) and within five years (ten years for resource plays) for probable undeveloped reserves. The Corporation has in recent years continually developed its undeveloped reserves in Canada and the United States. The Corporation intends to fund the development of its undeveloped reserves as of December 31, 2018 with cash, internally generated cash flow and/or debt. These expenditures are expected to extend the continual development of undeveloped reserves in Canada and the United States beyond two years.

In the Fort Berthold property, the Corporation has been active for the last several years in drilling and developing these undeveloped reserves, converting the associated volumes to producing reserves. The Corporation has, in the past, maintained the gross proved plus probable undeveloped location well count year over year and added undeveloped locations to replace those that were drilled in the preceding year. The Corporation expects to increase its activity in Fort Berthold and has increased the gross proved plus probable undeveloped location count from 130 locations in 2017 to 151 locations as of December 31, 2018. The conversion of the proved undeveloped locations to producing reserves is scheduled to occur continuously over the next three years and the development of the remaining probable undeveloped locations is scheduled to occur within four years.

In 2018, the Corporation continued to participate in the development of its non-operated undeveloped reserves in the Marcellus property, converting 6.2 net proved plus probable locations to developed reserves. These converted locations were replaced with additions of 8.3 net proved plus probable undeveloped locations as of December 31, 2018. Development timing for both proved undeveloped and proved plus probable undeveloped locations is determined by the scheduling prepared by the operators of the property. In this case, development of both the proved undeveloped and probable undeveloped locations is scheduled in each of the next five years.

In Canada, the Corporation's drilling activity level has been modest in recent years, and in 2018 consisted of drilling four gross proved plus probable undeveloped locations in Medicine Hat Glauc C and two gross proved plus probable undeveloped locations in the Ratcliffe property. Additional proved plus probable undeveloped locations were assigned in Giltedge (four gross), Medicine Hat Glauc C (five gross) and Ratcliffe (one gross) as of December 31, 2018. In addition to these properties, there are also undeveloped reserves assigned in the Cadogan property. Enerplus anticipates there will be drilling activity in these four properties starting in 2019. Development of the Canadian proved undeveloped reserves is forecast to occur continuously over the next two years, and the development of the probable undeveloped reserves is forecast to occur over the next four years.

SIGNIFICANT FACTORS OR UNCERTAINTIES

Changes in future commodity prices relative to the forecasts described above under "*Forecast Prices and Costs*" could have a negative impact on the Corporation's reserves and, in particular, on the development of undeveloped reserves, unless future development costs are adjusted in parallel. 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.

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. There are no unusually significant abandonment and reclamation costs associated with its reserves properties or properties with no attributed reserves, and the Corporation does not anticipate its abandonment and reclamation liabilities to negatively impact its reserves data or its ability to develop these reserves at this time.

For further information, see "*Risk Factors – The Corporation's actual reserves and resources will vary from its reserves and resources estimates, and those variations could be material*" and "*– Recent court rulings on the liability surrounding abandonment and reclamation obligations of oil and gas companies may adversely affect the Corporation".*

PROVED AND PROBABLE RESERVES NOT ON PRODUCTION

The Corporation has approximately 3.4 MMBOE of proved plus probable reserves which are capable of production but which, as of December 31, 2018, were not on production. These reserves have generally been non-producing for periods ranging from a few months to more than five years. In Canada, the majority of these reserves are related to reserves volumes associated with shut-in sour gas wells in Ferrier, which are to be tied-in to a different processing facility, and incremental polymer flood volumes in Giltedge. In the United States, the majority of these volumes are associated with non-operated wells drilled in 2018 in North Dakota that have not commenced production, and operated wells in Montana that are shut-in due to pump failures. All of these non-producing assets have been scheduled to recommence production in 2019 or 2020.

Supplemental Operational Information

SAFETY AND SOCIAL RESPONSIBILITY

The Corporation has adopted a Safety and Social Responsibility Policy (the "**S&SR Policy**"), which articulates its commitment to health and safety, environmental, stakeholder engagement, and regulatory compliance. The S&SR Policy applies to any activities undertaken by or on behalf of the Corporation in its operating areas. The Corporation's board of directors and the President & Chief Executive Officer are ultimately accountable for ensuring compliance with the S&SR Policy. The Corporation's management and its Safety & Social Responsibility department are responsible for ensuring that the S&SR Policy is implemented and communicated across the Corporation. All employees and contractors of the Corporation are responsible for complying with the S&SR Policy. The Safety & Social Responsibility Committee of the Corporation's board of directors (the "**S&SR Committee**") is responsible for overseeing the Corporation's S&SR performance and ensuring there are adequate systems in place to support ongoing compliance, and to plan and execute the Corporation's activities in a safe and socially responsible manner.

The Corporation strives to develop and operate its oil and natural gas assets in a socially responsible manner and places a high priority on protecting the health and safety of its employees, contractors, and the public in the communities in which it operates, as well as preserving the quality of the environment. The Corporation also encourages active and open collaboration with its stakeholders. The Corporation has established processes and programs designed to evaluate and minimize health, safety, and environmental risks, and strives for continuous improvement in its S&SR performance. The Corporation also actively participates in industry recognized programs, as well as certain international best practices, which support its sustainability goals.

The S&SR Policy discusses the Corporation's commitment to protect the health and safety of all persons and communities involved in, or affected by, its business activities. Specifically, the S&SR Policy outlines that the Corporation will:

- promote and support a culture in which all employees and contractors share ownership of a workplace where no one gets injured
- provide the resources, equipment and training needed to ensure everyone complies with its health and safety programs
- strive to continually improve its safety culture by integrating applicable industry best practices and operational experience into its health and safety mindset and programs

The S&SR Policy also states the Corporation's commitment to the environment and states that the Corporation will:

- proactively manage its impact on the environment and consider innovative improvement opportunities
- work to reduce its environmental impact in the areas in which it operates, including reviewing the efficiency of its energy consumption to reduce emissions intensity
- improve its water and land use practices
- limit the waste it generates
- prevent and manage environmental releases
- provide transparent disclosure
- provide resources and training to meet its environmental commitments

The Corporation's commitment to building meaningful and transparent relationships with its stakeholders is embedded in its S&SR Policy. In addition, the S&SR Policy expresses the Corporation's commitment to engaging with stakeholders to promote economic and social development for the people and communities in its operating areas.

Finally, the Corporation's commitment to the responsible development of resources and regulatory compliance is stated in its S&SR Policy and Corporate Sustainability Report (the "**Report**"), which the Corporation publishes annually in accordance with the Global Reporting Initiative international standard. The Report summarizes the Corporation's environmental, safety, social responsibility and governance performance, and can be found at www.enerplus.com.

Health and Safety

The Corporation's combined (employee/contractor) recordable injury frequency rate for 2018 was 1.13 injuries per 200,000 man hours, a decrease from the rate of 1.63 recorded in 2017. The Corporation's employee recordable injury frequency rate of 0.24 injuries per 200,000 man hours in 2018 was in line with 0.23 injuries per 200,000 man hours in 2017. The Corporation's total contractor recordable injury frequency of 1.53 injuries per 200,000 man hours in 2018 decreased from 2.64 injuries per 200,000 man hours in 2017. The Corporation recorded six lost-time injuries in 2018, an increase from three recorded in 2017. The Corporation has not had employee or contractor fatalities for any of the last five years**.**

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

- increase emphasis on safety awareness and promote continuous improvement and safety excellence
- provide staff with the training and resources needed to complete work safely
- incorporate hazard assessment and risk management as an integral part of everyday business
- monitor performance to ensure that its operations comply with all legal obligations and its internally-imposed standards

The health and safety component of the S&SR management system is reviewed annually for continuous improvement opportunities. The Corporation continues to develop and implement prevention measures and safety management program improvements to support its focus and commitment for an injury-free workplace.

Environment

The Corporation's operations are subject to applicable laws and regulations relating to the environment. See "*Industry Conditions – Environmental Regulation*". The Corporation is committed to meeting its responsibilities to protect the environment through a variety of programs and actively monitors its operations for compliance with all relevant and applicable environmental regulations and industry best practices. The Corporation engages in the following activities:

- Site abandonment and reclamation capital expenditures for the Corporation's Canadian and United States properties in 2018 totaled approximately $11.3 million ($9.2 million on operated properties and $2.1 million on non-operated properties). The Corporation received 19 reclamation certificates from regulatory agencies in 2018 by returning sites to their previous equivalent land capability.

- The Corporation undertakes third-party environmental compliance audits designed to ensure compliance with environmental legislation and regulations. In 2018, three environmental compliance audits were completed.

- The Corporation commissions third-party loss prevention audits to identify and evaluate the risk exposures associated with production equipment, process operations, utility supply systems and natural hazards. The purpose of the loss prevention audits is to generate detailed loss prevention reports with risk-based recommendations for improving the overall safety and performance of the Corporation's facilities, mitigating the potential exposure to financial loss associated with property damage and production loss, and ensuring the adequacy of its relevant insurance coverage. Two loss prevention audits occurred in 2018.

- Government regulators conducted 124 inspections of the Corporation's field operations in the United States and Canada in 2018, a reduction compared to the prior year's 235 government regulator inspections. The percentage of non-compliant field inspections received by the Corporation in 2018 was 9%, compared to the 12% received in 2017. However, the Corporation continued its internal facility inspection program and completed 19 inspections at major Canadian facilities in 2018. The average score of compliance resulting from the internal inspection program in 2018 was 91%, in line with the result of 92% in 2017.

- The Corporation conducts an internal site inspection program at its U.S. and Canadian locations to proactively assess environmental, regulatory and general housekeeping items. Findings from the internal site inspection program and any action items are recorded in the Corporation's internal Sustainability Information Management System in order to measure compliance and ensure potential issues are addressed.

- The Corporation conducts annual property reviews with specific risk reduction objectives. The Corporation also continues to manage risk through its ongoing pipeline risk assessment process and various other activities, such as inspections of pipelines at water crossings. The Corporation reviews each of its pipeline systems annually. The Corporation continues to incorporate improvements to these programs, which are designed to identify and mitigate significant risks, and to decrease the number and severity of pipeline failure incidents.

- The Corporation has estimated its direct emissions in 2018 to be approximately 796,499 carbon dioxide equivalent tonnes per year, which is 38% more than the Corporation's direct emissions in 2017 of 575,704 carbon dioxide equivalent tonnes per year. The increase was a result of the growth in liquids production during 2018**.** The estimated numbers will be confirmed as additional data becomes available. The Corporation does not expect to incur additional costs as a result of the emissions increases as it is in compliance with all relevant gas capture requirements.

- In 2018, the Corporation completed a total of 348 fugitive emissions surveys for its Canadian facilities and U.S. production pad facilities to detect losses from leaks and vents, and is working to repair all identified leaks. The Corporation does not expect the cost to remedy the leaks to be material.

Greenhouse gas ("**GHG**") regulations have been enacted in British Columbia, Alberta and at the federal level in Canada and the United States. In 2018, the Corporation's only area subject to active carbon tax regulations affecting its operations was in the jurisdiction of British Columbia. The total carbon tax paid was approximately $0.6 million in 2018. In addition, the Corporation is required to report third-party verified GHG emissions annually to the government of British Columbia pursuant to the *Greenhouse Gas Emission Reporting Regulation* (the "**Reporting Regulation**") enacted under the *Greenhouse Gas Industrial Reporting and Control Act*. In 2018, the Corporation was not subject to any Canadian federal greenhouse gas emissions reporting requirements as it did not operate facilities above the 10,000 tonnes of carbon dioxide equivalent ("**CO_{2e}**") per year, per facility threshold (the limit which came into effect in 2017). For its operations in the United States, the Corporation is subject to the reporting requirement under the U.S. Environmental Protection Agency (the "**U.S. EPA**") *Clean Air Act* and the Mandatory Reporting of Greenhouse Gases Rule. The latest of these reports was submitted to the U.S. EPA on March 31, 2018 for the 2017 operational year. For more information on the environmental regulation applicable to the Corporation, see "*Industry Conditions – Environmental Regulation"*.

The S&SR Committee regularly reviews health, safety, environmental and regulatory updates, and risks. At present, the Corporation believes 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 and performance 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 S&SR focus areas to support this commitment and sets forth strategic targets. The Corporation believes that by monitoring S&SR lagging and leading metrics, identifying areas for improvement, and implementing strategies, processes and procedures in those key focus areas, the Corporation will continue to improve its S&SR performance.

INSURANCE

The Corporation carries insurance coverage to protect its assets at 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 a number of risks including, but not limited to, third party liability, property damage, business interruption, terrorism, pollution and well control. In addition, liability coverage is also carried for the directors and officers of the Corporation.

PERSONNEL

As at December 31, 2018, the Corporation employed a total of 399 persons, including full-time benefit employees and payroll consultants, 254 of whom were in Canada and 145 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, By-law No. 1 and By-law No. 2 were filed on January 2, 2013, June 16, 2014, and May 6, 2016, respectively, on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

COMMON SHARES

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

The Articles contain provisions facilitating payment of dividends on Common Shares through issuance of Common Shares in circumstances where the board of directors declares, and a shareholder of the Corporation validly elects to receive, the payment of dividends, in whole or in part, in the form of Common Shares. See "*Dividends – Stock Dividend Program*".

PREFERRED SHARES

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

SHAREHOLDER RIGHTS PLAN

The continuation and amendment and restatement of the Shareholder Rights Plan was approved by shareholders of the Corporation, including by a requisite number of the Corporation's "Independent Shareholders" (as defined in the Shareholder Rights Plan), at the annual meeting held on May 6, 2016. The continuation of the Shareholder Rights Plan must next be approved by the Corporation's "Independent Shareholders" at the annual meeting of shareholders of the Corporation to be held on May 9, 2019, failing which it will expire at the end of such meeting. The Corporation has no intention to renew the Shareholder Rights Plan at the annual meeting of shareholders in 2019. As such, the Shareholder Rights Plan will expire in accordance with its terms on May 9, 2019.

SENIOR UNSECURED NOTES

Enerplus has issued Senior Unsecured Notes, of which US$489 million and CDN$30 million principal amounts were outstanding at December 31, 2018. Certain terms of the Senior Unsecured Notes are summarized below:

Issue Date	Original Principal	Remaining Principal	Coupon Rate	Interest Payment Dates	Maturity Date	Term
September 3, 2014	US$200 million	US$105 million	3.79%	March 3 and September 3	September 3, 2026	Principal payments required in five equal annual installments beginning September 3, 2022
May 15, 2012	CDN$30 million	CDN$30 million	4.34%	May 15 and November 15	May 15, 2019	Bullet payment on maturity
May 15, 2012	US$20 million	US$20 million	4.40%	May 15 and November 15	May 15, 2022	Bullet payment on maturity
May 15, 2012	US$355 million	US$298 million	4.40%	May 15 and November 15	May 15, 2024	Principal payments required in five equal annual installments beginning May 15, 2020
June 18, 2009	US$225 million	US$66 million	7.97%	June 18 and December 18	June 18, 2021	Principal payments required in three equal annual installments beginning June 18, 2019

For additional information see "*Material Contracts and Documents Affecting the Rights of Securityholders*". See also Note 7 to the Financial Statements.

BANK CREDIT FACILITY

As of December 31, 2018, the Corporation was undrawn on its $800 million senior unsecured, covenant-based credit facility with a syndicate of financial institutions maturing October 31, 2021.

For a description of the Bank Credit Facility, see Note 7 to the Corporation's Financial Statements. See also "*Material Contracts and Documents Affecting the Rights of Securityholders*".

Dividends

DIVIDEND POLICY AND HISTORY

The Corporation's board of directors is responsible for determining the dividend policy of the Corporation. The dividend policy must comply with the requirements of the ABCA, including satisfying the solvency test applicable to ABCA corporations. The Corporation currently has established a dividend policy of paying monthly dividends to holders of Common Shares. The dividend record date is on or about the last business day of each calendar month and the corresponding dividend payment date is on or about the 15th day of the following month. **However, any decision to pay dividends on the Common Shares will be made by the Corporation's board of directors on the basis of the relevant conditions existing at such future time, and there can be no guarantee that the Corporation will maintain its current dividend policy. Dividend amounts likely will 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 and other payments 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 not resident in Canada are subject to foreign exchange rate risk on such payments.

The table below sets forth the dividends paid or declared by the Corporation in 2016, 2017, 2018 and January through March of 2019:

Month	**2019**	**2018**	**2017**	**2016**
January	$ 0.01	$ 0.01	$ 0.01	$ 0.03
February	0.01	0.01	0.01	0.03
March	0.01	0.01	0.01	0.03
April	N/A	0.01	0.01	0.01
May	N/A	0.01	0.01	0.01
June	N/A	0.01	0.01	0.01
July	N/A	0.01	0.01	0.01
August	N/A	0.01	0.01	0.01
September	N/A	0.01	0.01	0.01
October	N/A	0.01	0.01	0.01
November	N/A	0.01	0.01	0.01
December	N/A	0.01	0.01	0.01

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

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

STOCK DIVIDEND PROGRAM

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

Industry Conditions

OVERVIEW

The Corporation, and the oil and natural gas industry generally, are subject to extensive controls and regulation governing operations (including land tenure, exploration, development, production, refining, transportation, marketing, remediation, abandonment and reclamation) imposed by legislation enacted by various levels of government. The Corporation and the oil and natural gas industry are also subject to agreements among the various federal, state and provincial governments with respect to pricing and taxation of oil and natural gas. Although it is not expected 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 producers in similar operating areas, the controls, regulations and agreements should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the Corporation's participation in the oil and gas industry that are applicable to the Corporation's operations.

The Corporation owns oil and natural gas properties and related assets in the United States (Montana, North Dakota, Pennsylvania and Colorado) and Canada (Alberta, Saskatchewan and British Columbia). The Corporation's oil and natural gas operations are regulated by a wide range of administrative agencies under statutory provisions of the states and provinces where such operations are conducted, by certain agencies of the federal government for operations on U.S. federal leases and, in some cases, by local agencies. These provisions regulate matters such as the exploration for and production of crude oil and natural gas, including rules 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 operations are also subject to various conservation laws and regulations in respect of 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, conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit or limit the venting or flaring of natural gas and associated liquids, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells. As well, the Corporation is required to disclose payments made to governments of all levels, including First Nations in Canada and Indian Reservations in the United States, as part of a transparency reporting initiative legislated by the Canadian government**.**

PRICING AND MARKETING OF CRUDE OIL AND NATURAL GAS

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

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

Internationally, prices for crude oil and natural gas fluctuate in response to changes in the supply and demand for crude oil and natural gas, market uncertainty, and a variety of other factors beyond the Corporation's control. Crude oil and natural gas prices have experienced significant volatility in response to a variety of factors including, among others, the increase in the global supply of crude oil and the ongoing decisions by the Organization of Petroleum Exporting Countries ("**OPEC**") and non-OPEC members, including Canada, to manage production levels to achieve balance in crude oil supply and demand. See "*Risk Factors – Oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Corporation's business, results of operations or cash flows and financial condition*". In addition, crude oil and natural gas producers in some areas of North America, such as Alberta, currently receive significantly discounted prices for their production relative to certain continental and/or international benchmark prices due to the lack of adequate egress which would allow crude oil and natural gas production to be transported and sold to national and, in some cases, international markets. See "*Risk Factors – Lack of adequately developed infrastructure, and the impact of special interest groups on such development, may result in a decline in the Corporation's ability to market its oil and natural gas production*".

ROYALTIES AND INCENTIVES

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

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

LAND TENURE

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

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

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

ENVIRONMENTAL REGULATION

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

British Columbia

In British Columbia, all oil and gas operations, including exploration, development, pipeline transportation and reclamation, are overseen by the British Columbia Oil and Gas Commission ("**BCOGC**"), primarily through the *Oil and Gas Activities Act*. The BCOGC also oversees compliance with a variety of environmentally-related statutes, including the *Forest Act*, *Heritage Conservation Act*, *Land Act*, *Environmental Management Act* and the *Water Sustainability Act*.

Alberta

In Alberta, the Alberta Energy Regulator ("**AER**") is the single regulator of energy development in Alberta and oversees all aspects of the regulatory process, including application and exploration, construction and development, abandonment, reclamation, and remediation activities. The AER oversees compliance with the *Oil and Gas Conservation Act*, *Public Lands Act* and the *Mines and Minerals Act,* the *Water Act* and the *Environmental Protection and Enhancement Act* by oil and gas operators.

Saskatchewan

In Saskatchewan, oil and gas exploration is overseen by the Ministry of Energy and Resources which administers legislation including *The Crown Minerals Act, The Oil and Gas Conservation Act* and *The Pipelines Act, 1998*. Environmental regulation is governed by the Ministry of Environment pursuant to the *Saskatchewan Environmental Code*, which consolidates rules under other statutes and, among other things, prescribes applicable levels of emissions without mandating express measures to achieve such levels.

United States

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

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

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

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

At the request of Congress, in 2011 the U.S. EPA began research under its *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. The purpose of the study was to assess the potential impacts of hydraulic fracturing on drinking water resources, and to identify the driving factors that may affect the severity and frequency of such impacts. The U.S. EPA published the final report in December 2016. The report did not identify systemic or widespread impacts to groundwater from hydraulic fracturing. There have been no further government actions or regulations as of the date of this Annual Information Form.

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

In 2016, the U.S. EPA finalized three air quality regulations potentially affecting the Corporation's operations. Two of the regulations are related to administrative permitting actions, which pose no additional operational costs for the Corporation. The third rule sets out additional emission control requirements for oil and gas sources. While the Corporation is now largely in compliance with these additional emission control requirements, there may be a risk of non-compliance when the rule is promulgated as final.

The BLM, which regulates oil and gas operations located on federal and tribal lands, including the Corporation's Fort Berthold operations, published its final hydraulic fracturing rules on March 26, 2015. Certain industry participants have objected to the proposed rules on various bases. On June 21, 2016, a federal District Court struck down the rules, concluding that the BLM had exceeded its regulatory authority with the new rules. BLM has filed an appeal to the decision, which is currently ongoing.

In July of 2014, the North Dakota Industrial Commission ("**NDIC**") finalized a rule that imposes restrictions on the flaring of gas. The rule establishes gas capture rates that must be met by operators to avoid the imposition of crude oil production curtailments. These gas capture rates went into effect in October 2014, and gas capture efficiencies have increased per the required timelines set out by the NDIC. The need for an operator to flare gas primarily stems from the fact that the rate of oil and gas development in North Dakota currently outpaces the construction of gas gathering and processing infrastructure. This situation is the result of various factors, including delays in obtaining right of way approvals, which is particularly cumbersome with respect to operations taking place on FBIR due to the application of additional regulatory requirements. The Corporation is working diligently with its midstream partner and the regulators to expand gas gathering capacity and increase gas capture rates. One measure being taken is the installation of NGL processing skids which are being used to extract NGLs from gas that would have otherwise been flared. See "*Risk Factors - Higher than expected declines or curtailments in the Corporation's production due to infrastructure constraints, third party operational business practices or failures, or government regulation could have an adverse effect on results of operations or cash flows and financial condition*". The Corporation received no NDIC orders to curtail crude oil production in 2018 and has consistently met or exceeded regulatory established gas capture rates since January 2015. Gas capture requirements were amended, moving to a more stringent 88% in November 2018, with a further increase to 91% by November 2020 under the current NDIC guidelines. The NDIC recently updated their gas capture policy to include additional consideration for gas capture calculations on Tribal land and announced their intention to work with the BLM and the FBIR to defer flaring and gas capture oversight for the FBIR to the MHA Nation in 2019.

In December of 2014, NDIC adopted conditioning standards aimed at improving the safety of crude oil when transported. The regulation focuses on ensuring that produced crude oil is sufficiently conditioned at the well site to remove volatility characteristics that might pose unreasonable transportation hazards, regardless of the mode of transportation utilized. The standards, which require quarterly sampling and analysis, became effective during the second quarter of 2015. The Corporation has been in compliance with the NDIC conditioning standards requirements since their inception and throughout 2018. In January 2019, the NDIC approved revisions to the conditioning standards, reducing the frequency of required sampling and analysis from quarterly to twice per year during the months of October through March.

On November 17, 2016, the BLM finalized new rules on the venting and flaring of produced gas, which imposed further limits on natural gas flaring, required additional gas leak detection and repair, and provided further clarification on associated royalty obligations. Many of the requirements set out in the rules are duplicative of existing state and U.S. EPA requirements, which are already applicable to and followed by the Corporation. The executive order, *Promoting Energy Independence and Economic Growth*, issued by the Trump Administration in 2017, resulted in the BLM rescinding many initial requirements of the venting and flaring rules effective November 2018, and largely deferring to state and Tribal regulations.

The 2018 Colorado state election resulted in a newly elected state government. The Corporation is working closely with industry partners and trade associations, and building relationships to encourage business certainty and clarity on proposed changes in regulations. Enerplus' Colorado operations are subject to stringent regulatory programs and strict enforcement. As a result, active stakeholder engagement and outreach, coupled with implementing a strong regulatory compliance program, are key priorities of the Corporation in 2019 and onward.

Implementation of more stringent environmental regulations on the Corporation's U.S. operations could affect the Corporation's capital and operating expenditures and plans. The Corporation minimizes the potential of these impacts to U.S. operations in many ways, including through participation and membership in trade organizations such as the North Dakota Petroleum Council, Montana Petroleum Association, Independent Petroleum Association of America, Western Energy Alliance and the Colorado Oil and 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 comments on proposed legislation and regulations. As in Canada, the Corporation's U.S. operations endeavour to carry out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice.

Climate change legislation

Climate change legislation at each of the provincial, state and federal levels has the potential to significantly affect the oil and gas industry regulatory environment and impose significant financial obligations.

Both Canada and the U.S. were part of the United Nations Framework Convention on Climate Change ("**UNFCCC**") meeting in Paris in 2015. A binding commitment was signed by all panel countries that set a target of no more than a two-degree Celsius warming of the earth based on GHG levels in the atmosphere. This commitment to limit warming may increase provincial, state and federal GHG regulatory rigour as country-level emissions will be reviewed periodically in subsequent meetings to assess alignment with the targets agreed upon. In June of 2017 the U.S. announced its intention to withdraw from the Paris Agreement, delivering written notice of such to the United Nations on August 4, 2017.

Although the United States announced its withdrawal from the Paris Agreement, federally the U.S. EPA has issued GHG emissions regulations pursuant to the Clean Air Act that establish a reporting program for CO_2, methane and other GHG emissions. It has also established a permitting program for certain large GHG emissions sources. While the United States Congress has considered numerous legislative initiatives to reduce or tax GHG emissions, to date no laws in that regard have been enacted. On a state level, some states have enacted laws concerning GHG emissions. However, many of them are being challenged.

The Government of Canada is working toward the two-degree target on a sector by sector basis, but has yet to finalize regulations pertaining to the oil and gas sector. As part of its commitment under the Paris Agreement, the Canadian federal government developed the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**") in 2016, together with provincial (except Saskatchewan, Ontario and Manitoba as these provinces have recently announced their intention to withdraw) and territorial leaders in consultation with Canada's Indigenous Peoples, to meet Canada's emission target while enabling economic growth.

Under the Framework, the federal government will require all jurisdictions to develop a carbon pricing system that is equivalent to $10 per tonne in 2018 and rising by $10 per year to $50 per tonne in 2022. Jurisdictions can implement: (i) an explicit price-based system (such as the carbon tax adopted by British Columbia or the carbon levy and performance-based emissions system adopted in Alberta), or (ii) a cap-and-trade system (which has been adopted in Ontario and Quebec). Within these programs, provinces have discretion to manage competitiveness of their trade-exposed industries. In June of 2018, the Government of Canada's federal carbon pricing system, entitled the *Greenhouse Gas Pollution Pricing Act* ("**GHGPPA**") received royal assent. The GHGPPA is only intended to act as a regulatory backstop in the event a province or territory does not otherwise implement an adequate GHG regime. It is currently unclear what impact the GHGPPA will have on the Corporations' operations, particularly in Saskatchewan and Alberta.

To complement carbon pricing, the federal government is designing a Clean Fuel Standard with the objective of achieving annual reductions of 30 Mt of GHG emissions by 2030 and driving investment in low carbon fuels. The approach is based on separate life cycle analysis for liquid, gaseous and solid fuels and will not differentiate between crude oil types produced in or imported into Canada. This standard is expected to apply to a broad suite of fuels used in transportation, industry, homes and buildings. The federal government released a Regulatory Design Paper in December of 2018 and final publication of regulations that outlines carbon intensity limits for the liquid fuels stream is expected in 2020, with requirements to be enforced by 2022. Gaseous and solid fossil fuel final regulations are expected in 2021, with requirements to be enforced by 2023. As the standard is still under development, the Corporation is unable to predict the impact it will have.

The Canadian federal government also issued *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Regulations**") in April of 2018. The intent of the Regulations is to reduce methane emissions by 40% to 45% below 2012 levels by 2025. These Regulations become applicable in any province or territory that chooses not to develop equivalent regulations. The Regulations have two stages of implementation: Stage 1 (leak detection and repair, venting from well completions and compressors), which will be in effect in 2020 and Stage 2 (venting restrictions and pneumatics), which will be in effect in 2023. The Provinces of Alberta, British Columbia, and Saskatchewan are currently seeking equivalency with the federal government and if this is successful, the relevant provincial requirements will be in effect for the Corporation.

In 2008, the Province of British Columbia instituted a carbon tax that applies to all fuel users and purchasers in the province. The tax for 2019 is $40 per tonne of CO_{2e}, and will increase by $5/tonne annually. Under the Reporting Regulation, facility operators are required to submit third party verified GHG emissions annually to the Province. See "*Supplemental Operational Information – Safety and Social Responsibility – Environment*". The Province of British Columbia is in discussions with stakeholders and partners of the Western Climate Initiative to develop a regional cap and trade program. The Corporation is unable to estimate the future potential compliance costs of this program without a carbon price or an allocation of emission allowances. Given the Corporation's current hydrocarbon production levels and lack of development activity in British Columbia in recent years, the Corporation does not expect such costs to be material.

Effective January 1, 2017, the Province of Alberta enacted the *Climate Leadership Act*, which imposes a carbon levy on consumers for all GHG emissions arising from the combustion of fuels for heating and transportation. The levy is currently $35 per tonne of CO_2e emissions, however, oil and gas producers are exempt from this tax for fuel used in a production process until 2023. In addition, the Province of Alberta has established a reduction goal of 45% for methane gas emissions by 2025. To achieve that goal, in December 2018 the Alberta Energy Regulator issued prescriptive measures to reduce methane by implementing emissions design standards on new facilities, addressing venting from existing equipment, and increasing measurement, reporting and fugitive emissions requirements. These requirements intend to achieve equivalency with the federal methane emissions reduction regulations issued in April 2018. The Corporation estimates it could incur an additional $300,000 per year in costs due to equipment retrofits, increased measurement and reporting work, and higher frequency of fugitive leak inspections. Alberta also has emission reduction targets for large emitters (e.g., 100,000 tonnes of CO_2e per year at a single facility). Currently, the Corporation does not operate any facility classed within this large emitter category.

In May of 2010 the Province of Saskatchewan's *The Management and Reduction of Greenhouse Gases Act* ("**GHG Act**") received royal assent with only certain portions proclaimed in force on January 1, 2018. The Province of Saskatchewan has established a goal of reducing GHG emissions from the province's upstream oil and gas sector by 40% to 45% from 2015 levels by 2025. In December of 2017, the Government of Saskatchewan released a climate change strategy entitled *Prairie Resilience: A Made in Saskatchewan Climate Change Strategy* (the "**Strategy"**) to affirm provincial regulatory jurisdiction over emissions regulation. This Strategy focuses on sector-specific approaches and climate change adaptation. The Government of Saskatchewan has publicly stated that the Saskatchewan regulatory package provides an alternative, robust plan to the federal GHG emission reduction regulations to help Saskatchewan achieve climate change goals, while also providing industry with the flexibility to implement measures in an effective, economically viable way. Pursuant to the Strategy, the Province of Saskatchewan released *The Oil and Gas Emissions Management Regulations* (the "**OGEMR**"), which came into effect January 1, 2019 and are applicable to entities whose combined potential emissions are greater than 50,000 tonnes of CO_2e per year. Currently, the Corporation's annual emissions in Saskatchewan are well beneath this threshold. The Province of Saskatchewan is currently challenging in court the federal government's plan to impose a carbon tax. Saskatchewan believes its climate change plan, which does not include a carbon tax, is enough to reduce emissions. Until a decision has been made by the Saskatchewan Court of Appeal, the Corporation will assess the carbon tax impacts on its Saskatchewan operations based on rates outlined in the federal GHGPPA.

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 costs of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. See "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including those related to climate change, as well as public opposition and activism*" and "*Risk Factors – Government policy and/or regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs*".

WORKER SAFETY

The Corporation's oilfield operations must be carried out in accordance with safe work procedures, rules and policies contained in applicable safety legislation. Such legislation requires that every employer ensures the health and safety of all persons at any of its work sites and all workers engaged in the work of that employer. The legislation, which provides for incident reporting procedures, also requires every employer to ensure 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. The Corporation is currently in compliance with applicable safety legislation.

Risk Factors

The following risk factors, together with other information contained in this Annual Information Form and other filings, including the Corporation's MD&A, and its Financial Statements and related notes, should be carefully considered before investing in the Corporation. Each of these risks may negatively affect the trading price of the Common Shares or the amount of dividends that may, from time to time and at the discretion of the Corporation's board of directors, be declared and paid by the Corporation to its shareholders.

Please note, all references to "natural gas" in this section refer to both natural gas and shale gas.

Oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Corporation's business, results of operations, or cash flows 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. These price fluctuations have been in response to a variety of factors beyond the Corporation's control, including:

- global energy supply and demand, production and policies, including the ability of OPEC or non-OPEC members to set, maintain, or reduce production levels to help in achieving a balanced market
- political conditions, including the risk of hostilities in the Middle East and global terrorism
- global and domestic economic conditions and currency fluctuations
- the level of consumer demand, including demand for different qualities and types of crude oil, NGLs and natural gas
- the production and storage levels of North American natural gas and crude oil, and the supply and price of imported oil and liquefied natural gas
- weather conditions
- the proximity of reserves and resources to, and capacity of, transportation facilities, and the availability of refining, processing and fractionation capacity
- the ability, considering regulation, taxation, and market demand, to export crude oil and liquefied natural gas and NGLs from North America
- the effect of world-wide energy conservation and greenhouse gas reduction measures and the price and availability of alternative fuels
- existing and proposed changes to government regulations and policy decisions

Oil and natural gas producers in North America may receive significantly discounted prices for some of their production due to regional constraints on the ability to transport and sell such production to international markets. Additionally, limited natural gas and NGLs processing capacity or other infrastructure constraints may result in producers not realizing the full price for their production. The inability to resolve such constraints may result in continued reduced commodity prices received by oil and natural gas producers such as the Corporation.

Future declines in crude oil and/or natural gas prices, or an extended low commodity price environment, may have a material adverse effect on the Corporation's operations and cash flows, 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 proceed with as part of the Corporation's exploration or development plans or projects if commodity prices are low, thereby impacting the Corporation's production volumes. Low prices may also impact the Corporation's desire to market its production under unsatisfactory market conditions. Alternatively, due to regulatory or contractual obligations, the Corporation may be required to produce from or develop certain properties to fulfill its obligations despite unsatisfactory market conditions for marketing of any production therefrom, increasing the risk of financial losses. Furthermore, the Corporation may be subject to the decisions of third party operators who, independently and using different economic parameters than the Corporation, may decide to curtail or shut-in jointly owned production.

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

The oil and gas industry operates under federal, provincial, state and municipal legislation and regulation governing such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, the imposition of specific drilling obligations, the imposition of production curtailments, control over the development and abandonment of fields (including restrictions on production), restrictions on the combustion of natural gas and possibly expropriation or cancellation of contract rights. See "*Industry Conditions*". To the extent the Corporation fails to comply with applicable government regulations or regulatory approvals, the Corporation may be subject to compliance and enforcement actions that are either remedial, which are intended to fix the noncompliance and any related impacts, or punitive, which are intended to deter future noncompliance. Such actions include fines or fees, notices of non-compliance, warnings, orders, administrative sanctions, and prosecution. In addition, obstructive tactics which could prevent certain measures from being voted upon in the United States legislature, or any government action resulting in a prolonged government shutdown, may impact the Corporation as a result of its inability to obtain regulatory and other approvals.

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. U.S. federal and state and Canadian federal and provincial governments continue to scrutinize the usage and disposal of chemicals and water used in fracturing procedures in the oil and gas industry, while certain states have called for bans on oil and gas drilling using hydraulic fracturing. More activity by the Corporation on Indian lands in the United States, or lands held by Indigenous groups in Canada, may also increase compliance obligations under tribal or local 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, or restrict the supply of, crude oil and natural gas production, or impose increased costs on oil and gas companies, any of which could have a material adverse impact on the Corporation.

Additionally, various levels of Canadian and U.S. governments are considering, or have implemented, legislation to reduce emissions of greenhouse gases, including volatile organic compounds. See "*Industry Conditions – Environmental Regulation*" for a description of these initiatives. Because the Corporation's operations emit various types of GHGs, such new legislation or regulations 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 GHG emissions, shut-in production, pay taxes, fees and other penalties related to its GHG emissions, and administer and manage a GHG emissions program. Currently, the Corporation is not able to estimate such increased costs; however, they could be material. Any of the foregoing could have adverse effects on the Corporation's business, financial position, results of operations and prospects.

The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including those related to climate change, as well as public opposition and activism.

GENERAL

The oil and natural gas industry elicits concerns about climate change, as well as general public opposition to the industry. As a result, industry participants may be subject to increased public activism, as well as extensive environmental regulation pursuant to local, provincial, and federal legislation in Canada and federal and state laws and regulations in the United States. Activist activity may result in increased costs due to delays or damage, while defaults by the Corporation under applicable legislation could result in the imposition of fines or the issuance of "clean up" orders. Legislation regulating the industry may be changed to impose higher standards and potentially more costly obligations, such as legislation requiring significant reductions in GHG emissions or setback requirements for facilities and wells. Failure to comply with such regulations and laws can result in significant increases in costs, penalties, or loss of operating licenses. The actual form of such legislation or regulation is evolving. Further, the business of exploration, development and production of oil and natural gas wells and facilities is subject to the risks and hazards associated with such operations. These include, but are not limited to, blowouts, fire, explosion, environmental releases (including sour gas), induced seismicity, and other safety hazards, which could result in significant damage to the Corporation's property, personal injury, loss of life, and liability to regulators or third parties.

The Corporation is not fully insured against all 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 damage) 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 for development of projects and resources, debt repayments, or as available cash for dividends to shareholders. Further, the availability in some jurisdictions of monies collected via levies on oil and gas producers, in order to cover remediation and/or reclamation costs incurred by the Corporation on behalf of insolvent or defunct partners, may be reduced or eliminated as such funds become depleted. Should the Corporation be unable to fully fund the cost of remedying an environmental claim, the Corporation might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

RISKS RELATING TO FRACTURING

The Corporation utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated drilling fluids, and other technologies in connection with its drilling and completion activities. There has been public concern over the hydraulic fracturing process. Most of these concerns have raised questions regarding the drilling fluids and the volume of fluid used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations, the ability of such water to be recycled, and induced seismicity associated with fracturing. The U.S. and Canadian governments, including certain U.S. state and Canadian provincial governments, may review 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. Claims have been made that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity, particularly where operators are in proximity to pre-existing faults. Governmental authorities in jurisdictions where the Corporation does not currently operate have either implemented or considered temporary moratoriums on hydraulic fracturing until further studies can be completed, and some governments have adopted or 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 requirements with respect to water usage or disposal, 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.

RISKS RELATING TO CLIMATE CHANGE

Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism, including threats of culpability, legal action against oil and gas producers, and public opposition to fossil fuels and the oil and gas industry in which the Corporation operates. See "*Industry Conditions – Environmental Regulation*". Public and government hostility toward the oil and gas industry could reduce demand for oil and gas and, therefore, adversely affect market prices for the Corporation's production. Existing and future laws and regulations may impose additional costs on companies operating in the oil and gas industry or significant liabilities for failure to comply with their requirements. Concerns over climate change and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general.

Lack of adequately developed infrastructure, and the impact of special interest groups on such development, may result in a decline in the Corporation's ability to market its oil and natural gas production.

The Corporation's business depends in part upon the availability, proximity, and capacity of oil and natural gas gathering systems, pipelines and/or rail transportation systems and processing facilities to provide access to markets for its production. U.S. federal and state, as well as Canadian federal and provincial, regulation of oil and natural gas production and processing and transportation could adversely affect the Corporation's ability to produce and market oil, natural gas and NGLs. Special interest groups could also oppose infrastructure development, resulting in delays or even cancellation of construction of the required infrastructure, further impeding the Corporation's ability to produce and market its products. In addition, the assets of the Corporation are concentrated in regions with varying levels of government regulations, or under tribal or local rules that could result in the imposition of a limit or ban on shipping of commodities by truck, pipeline or rail.

OIL AND NATURAL GAS GATHERING SYSTEMS

Development of new resource plays generally results in a sharp increase in the volume of oil and natural gas being produced in the area, which could exceed government-regulated gas capture requirements, or the existing capacity of the various gathering system infrastructure. The Corporation relies on the timely construction of adequate gathering systems that allow its crude oil and natural gas production to be transported from the wellhead to existing and/or new sales infrastructure systems, such as pipelines or rail terminals.

The pace at which producer or midstream companies can construct adequate gathering infrastructure to capture the natural gas associated with the development of crude oil and NGLs properties may have an impact on the Corporation's ability to increase crude oil production in its producing regions. Additionally, as exploration and drilling in these regions increases, the amount of natural gas being produced by the Corporation and others could exceed the capacity of the various gathering pipelines available in those areas. If these constraints remain unresolved, the Corporation's ability to transport its production to sales pipelines in these regions may be impaired and could adversely impact the Corporation's production volumes or realized prices in these areas.

SALES PIPELINES AND RAIL TRANSPORTATION SYSTEMS

Oil and natural gas producers in certain regions of North America may receive significantly discounted prices relative to benchmark prices for their production due to constraints on the ability to transport and sell such production to domestic and international markets. While third party pipeline and railroad companies generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of sales pipeline and rail capacity. This is currently the case with natural gas and crude oil sales pipelines in Alberta and British Columbia, as there is generally inadequate sales pipeline capacity to transport production out of these regions, resulting in volume curtailments and low regional commodity prices. To a lesser extent this risk exists with natural gas and crude oil sales pipeline capacity in North Dakota. Unfavourable economic conditions or financing terms, as well as significant delays in the regulatory approval process, may defer or prevent the completion of certain pipeline projects, gathering systems or railway projects that are planned for such areas. There may also be operational or economic reasons, including but not limited to maintenance activities, for curtailing transportation capacity. In addition, there could be legal or regulatory challenges by third parties on existing sales pipelines, which could impact a pipeline's ability to provide services to shippers. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all the production from a given region, causing added expense and/or volume curtailments for all shippers. To the extent that the transportation capacity becomes insufficient in areas where the Corporation operates, the Corporation may have to defer the development of, curtail production from or shut-in wells awaiting a pipeline connection or other available transportation capacity, and/or sell its production at lower prices than it would otherwise realize or it had projected to realize. This would adversely affect the Corporation's results of, and cash flow from, operations.

The Corporation transports its crude oil production by a diverse mix of pipeline, trucking and, on occasion, rail (after title is transferred to the buyer's name), all of which are subject to various risks of cost escalation and/or new costs. In certain regions the Corporation is currently dependent upon only one means of transportation. With respect to rail transportation, there may be future incremental costs associated with transporting, and there is a risk that access to rail transport may be constrained, depending upon changes made to existing rail transport regulations. More stringent government regulations concerning the usage of certain types of tank cars that transport crude oil and NGLs by rail in the United States and Canada have been enacted, and this could increase the cost of utilizing rail to transport crude oil and/or NGLs. In addition, oil and natural gas volumes being shipped by pipelines are required to meet certain quality specifications, which vary by pipeline. Should crude oil, natural gas or NGLs quality specifications fail to be met by a producer that is shipping volumes on a pipeline, the pipeline could shut down or curtail volumes of other producers shipping on that pipeline. Any shutdown, curtailment, reversal of pipeline flow, or a change in the commodity being transported on pipelines shipping volumes of the Corporation's production may impact the Corporation's ability to reach its intended market, or deliver fully on its obligations.

ACCESS TO PROCESSING FACILITIES

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

Crude oil and natural gas production requires processing at certain facilities in order to be transported on regional pipeline systems. The Corporation and the industry rely on the addition of adequate natural gas and other processing capacity to ensure the timely and economic processing of natural gas production, and the continued production of crude oil and NGLs, as well as any associated natural gas production. Limited natural gas processing capacity in certain regions may result in producers not being able to sell some or all of their natural gas production, lead to curtailment of crude oil production, or result in not realizing the full value of their natural gas production.

A failure to resolve any of the constraints described above may result in the Corporation failing to comply with certain environmental regulations, shutting-in production, or receiving continued reduced commodity prices.

An increase in capital or operating costs could have a material adverse effect on results of operations or cash flows and financial condition.

Higher capital or operating costs associated with the Corporation's operations will directly impact its capital efficiencies and/or decrease the amount of the Corporation's cash flow. Capital costs of completions, specifically the costs of proppant, pumper services, and operating costs such as electricity, chemicals, supplies, energy services and labour costs, are a few of the Corporation's costs that are susceptible to material fluctuation. Although the Corporation has a portion of its current capital and operating costs protected with existing agreements, changing regulatory conditions, such as those in the U.S. requiring certain raw materials, such as steel, for use in U.S. businesses to be sourced from the U.S., or that goods and/or services be procured from specific vendors or classes of vendors, may result in higher than expected supply costs for the Corporation.

Higher than expected declines or curtailments in the Corporation's production due to infrastructure constraints, third party operational business practices or failures, or government regulation could have an adverse effect on results of operations or cash flows and financial condition.

Continued industry production growth for any of the Corporation's products may exceed the capacity of existing pipeline infrastructure until debottlenecking is undertaken or completed. During such periods, regional prices may decline to levels where the Corporation considers, or governments mandate, curtailment of production. In some cases, alternate shipping methods, such as rail for crude oil, may be used and could result in higher costs and lower netbacks. In addition, the continuing production from a property, and to some extent the marketing of that production, is dependent upon the abilities of the operators of the Corporation's properties. A significant portion of the Corporation's production is from properties operated by third parties. This results in significant reliance on third party operators in both the operation, including the decision to curtail production due to low prices, and the development of such properties.

Operating agreements governing properties not operated by the Corporation typically require the operator to conduct operations in a "good and workmanlike" manner. These operating agreements generally exempt the operator from liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except for liabilities that may result from the operator's gross negligence or wilful misconduct. To the extent a third-party operator fails to perform its duties properly, faces capital or liquidity constraints or becomes insolvent, the Corporation's results of operations may be negatively impacted.

The timing and amount of capital required to be spent by the Corporation may also differ from the Corporation's expectations and planning, and may impact the ability of and/or cost to the Corporation to finance such expenditures, as well as adversely affect other parts of the Corporation's business and operations.

As a result of the foregoing, the Corporation may be required to curtail or shut-in production, which could damage a reservoir and potentially prevent the Corporation from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. In addition, the lower levels of production could result in a material reduction to the Corporation's cash flow, or may result in the Corporation incurring additional operating and capital costs for the well(s) to achieve prior production levels.

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

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

The Corporation's expanded scope of activities and participation in the capital markets may attract increased criticism, shareholder activism and costly litigation.

The expansion of the Corporation's business activities, both geographically and with a focus on exploration and development of unconventional reservoirs, may draw increased attention from shareholder activists who oppose the strategy of the Corporation, including its operation of the business, its plans for development and its capital allocation decisions, which could have an adverse effect on market value. The Corporation's ongoing participation in the Canadian and U.S. capital markets may expose the Corporation to greater risk of class action lawsuits related to, among other things, securities law matters (including with regard to alleged deficiencies in the Corporation's public disclosure), title, contractual and environmental matters.

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

Tax laws, including those that may affect the taxation of the Corporation, or other laws or government incentive programs relating to the oil and gas industry generally, may be changed, or interpreted in a manner that adversely affects the Corporation and its securityholders. Canadian, U.S. and foreign tax authorities having jurisdiction over the Corporation (whether as a result of the Corporation's operations or its financing structures), may change or interpret applicable tax laws, treaties or administrative positions in a manner which is detrimental to the Corporation or its securityholders. Tax authorities may disagree with how the Corporation calculates its income for tax purposes. The Corporation may be subject to additional taxation (direct or indirect, including carbon tax, goods and services tax, or sales tax), levies or royalty payments imposed by government and tribal authorities with jurisdiction over its properties. The Corporation has income and other 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. In addition, the U.S., Mexico and Canada negotiated certain changes to NAFTA, as proposed in the USMCA (U.S.-Mexico-Canada Agreement), which may lead to the imposition of additional duties and tariffs, and could result in other changes that could negatively impact the Corporation's business.

Changes in market-based factors and investor strategies may adversely affect the trading price of the Common Shares and/or the Corporation's stock exchange listings.

The market price of the Common Shares is primarily a function of the value of the properties owned by the Corporation, as well as the anticipated growth in production and cash flow, and dividends paid to shareholders. The market price of the Common Shares is also sensitive to a variety of market-based factors, including, but not limited to, an increase in passive investing (through vehicles such as exchange traded funds) and options trading, the inclusion or removal of the Common Shares from one or more stock market indexes or exchange traded funds, interest rates, and the comparability of the Corporation's performance to other growth or yield-oriented exploration and production companies. Additionally, the Common Shares may, from time to time, not meet the investment criteria or characteristics of a particular institutional or other investor, including for reasons unrelated to financial or operational performance. Any changes in market-based factors or investor strategies, including responsible investing criteria/rankings (for example, social impact or environmental scores), the implementation of new financial market regulations such as the Markets in Financial Instruments Directive (MiFID II) and fossil fuel divestment initiatives undertaken by governments, pension funds and/or other institutional investors, may adversely affect the trading price of the Common Shares, and/or their inclusion in the portfolios of investment managers. In addition, should the trading price of the Common Shares fall below stock exchange listing thresholds, the exchanges will review the appropriateness of the Common Shares for continued listing (NYSE) or ongoing listing (TSX).

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

The Corporation's unconventional oil and gas operations (such as the development of and production from shale formations) involve certain additional risks and uncertainties. The drilling and completion of wells and operations on these unconventional assets present certain challenges that differ from conventional oil and gas operations. Wells on these properties generally must be drilled deeper than in many other areas, which makes the wells more expensive to drill and complete. To reduce costs, wells may be drilled as part of a multi-well pad which may increase the risk of being unable to drill and complete any of the wells on the pad if problems occur. In addition, because of the depth and length of these unconventional wells, they also may be more susceptible to mechanical problems associated with drilling and completion, such as casing collapse and lost equipment in the wellbore. In addition, the fracturing activities required to be undertaken on these unconventional assets may be more extensive and complicated than fracturing the geological formations in the Corporation's other areas of operation and require greater volumes of water than conventional wells. The management of water and the treatment of produced water from these wells may be more costly than the management of produced water from other geologic formations. In addition, to the extent the Corporation acquires properties or assets with a higher exploration risk profile, the risk associated with such acquisitions and the future development of those assets is more uncertain.

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

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

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

The value of the Common Shares depends upon, among other things, the reserves and resources attributable to the Corporation's properties. The actual reserves and resources contained in the Corporation's properties will vary from the estimates summarized in this Annual Information Form and those variations could be material. Estimates of reserves and resources are by necessity projections, and thus are inherently uncertain. The process of estimating reserves or resources requires interpretations and judgments on the part of petroleum engineers, resulting in imprecise determinations, particularly with respect to new discoveries. Different engineers may make different estimates of reserves or resources quantities and revenues attributable thereto based on the same data. The reserves and resources information contained in this Annual Information Form is only an estimate. A number of factors are considered and a number of assumptions are made when estimating reserves and resources, such as, among others described in this Annual Information Form:

- historical production in the area compared with production rates from similar producing areas
- future commodity prices, production and development costs, royalties and planned capital expenditures
- initial production rates and production decline rates
- ultimate recovery of reserves and resources and the success of future exploitation activities
- marketability of production
- the effects of government regulation and other government royalties or levies, such as environmental costs, that may be imposed over the producing life of reserves and resources

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

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

Reserves and resources estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil, natural gas and NGLs prices and operating costs. Market price fluctuations of commodity prices may render uneconomic the recovery of certain categories of petroleum or natural gas. Moreover, short-term factors may impair the economic viability of certain reserves or resources in any particular period. With commodity prices remaining volatile, there is a risk for write-downs under U.S. GAAP. See "*Risk Factors – Lower oil and gas prices and higher costs increase the risk of write-downs of the Corporation's oil and gas properties and deferred tax assets*". Write-downs may lead to the Corporation breaching its covenants under the Bank Credit Facility, and the Corporation may not be able to negotiate any covenant relief. See "*Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief.*"

The Corporation may be unable to compete successfully with other organizations in the oil and natural gas industry, or obtain required vendor services to compete.

The oil and natural gas industry is highly competitive. The Corporation competes for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled/qualified labour, access to drilling rigs, service rigs and other equipment and materials such as sand and other proppant, hydraulic fracturing pumping equipment and related skilled personnel, access to processing facilities, pipeline and refining capacity, as well as many other services, 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 opportunities and more diverse resources to draw upon. Also, organizations that have complementary activities or are integrated may have access to, or be able to access, services or vendors that the Corporation is not able to access, thereby limiting its ability to compete.

Service providers are also in a highly competitive environment. Should low commodity prices prevail, some may choose or be required to streamline or discontinue their business, further reducing the supply of vendors and potentially increasing the competition for service, and thereby the costs to producers.

In addition, the Corporation may be at a competitive disadvantage to other industry participants able to minimize taxes under more favourable tax jurisdictions and/or regulatory environments, or which have access to a lower cost of capital.

Delays in payment for business operations, including the risk of default by counterparties to contracts, could adversely affect the Corporation.

In addition to the potential 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 or any counterparties to contracts (including the Corporation’s risk management, marketing, purchase and sale agreements, supplier and service contract counterparties) may also be delayed, or result in default due to, among other things:

- substantial or extended declines in oil, NGLs and natural gas prices
- capital or liquidity constraints experienced by such parties, including restrictions imposed by lenders
- accounting delays or adjustments for prior periods
- shortages of, or delays in, obtaining qualified personnel or equipment, including drilling rigs and completions services
- delays in the sale or delivery of products, or delays in the connection of wells to a gathering system
- adverse weather conditions, such as freezing temperatures, storms, flooding and premature thawing
- blow-outs or other accidents
- title defects
- recovery by the operator of expenses incurred in the operation of the properties, or the establishment by the operator of reserve funds 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. Any of these delays could also expose the Corporation to additional third-party credit risks.

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

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

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

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

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

Under U.S. GAAP, the net capitalized cost of oil and gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer's fiscal quarter and annual fiscal periods. The amount by which the net capitalized costs exceed the discounted value will be charged to net income. The Corporation incurred no non-cash asset impairments in 2018.

Under U.S. GAAP, the net deferred tax assets of a corporation are limited to the estimate of future taxable income resulting from existing properties. The Corporation estimates future taxable income based on before-tax future net revenue from proved plus probable reserves, undiscounted, using forecast prices, and adjusted for other significant items affecting taxable income. The amount by which the gross deferred tax assets exceed the estimate of future taxable income will be charged to net income. A previously recorded valuation allowance can be reversed if the estimate of future taxable income increases.

If commodity prices were to decline, there remains a risk for additional write-downs under U.S. GAAP. While these write-downs would not affect cash flow, the charge to earnings may be viewed unfavourably in the market. Additional write-downs may lead to the Corporation breaching its covenants under the Credit Facilities, and the Corporation may not be able to negotiate any covenant relief. See "*Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief.*"

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

In the normal course of making capital investments to maintain and/or 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 divest of existing properties or assets 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, become limited, unavailable or available on less favourable terms, the Corporation's ability to make the necessary capital investments to: (i) retain leases, (ii) carry out its operations, and/or (iii) maintain and/or expand its oil, NGLs and natural gas reserves and resources could be adversely affected. 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 may not realize the anticipated benefits of its acquisitions or divestments.

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 current or 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 those that are higher risk/higher growth assets and the development of those acquired assets, may require more capital than anticipated 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.

The Corporation may also from time to time seek to divest of properties and assets. These divestments may consist of non-core properties or assets, or may consist of assets or properties that are being monetized to fund debt repayment, alternative projects, or development by the Corporation. There can be no assurance that the Corporation will be successful in such divestments, or realize the amount of desired proceeds from such divestments, or that such divestments will be viewed positively by the financial markets, and such divestments may negatively affect the Corporation's results of operations or the trading price of the Common Shares. In addition, although divestments typically transfer future obligations to the buyer, the Corporation may not be exempt from certain obligations in the future, including for example, abandonment and reclamation obligations, which may have an adverse effect on the Corporation's operations and financial condition.

The Corporation's risk management activities, as well as ongoing regulatory changes affecting financial institutions, could expose it to losses.

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

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

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

Dividends and other payments on the Corporation's Common Shares are variable.

Although the Corporation currently intends to continue to return cash to shareholders with a monthly cash dividend payment and/or share repurchases, investor returns may change from time to time due to changes in the amount of the cash dividend paid or shares repurchased. With regard to the dividend, cash dividends are declared in Canadian dollars and are 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 may be reduced when converted to shareholders' home currency. In addition, shareholders may be subject to withholding taxes in accordance with tax treaties or domestic tax law changes, as determined by shareholder residency.

The amount of cash available to the Corporation to pay dividends or repurchase shares can vary significantly from period to period for many reasons including, among other things:

- 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)
- fluctuations in the costs to produce oil, NGLs and natural gas, including royalty burdens, and costs to administer and manage the Corporation and its subsidiaries
- the amount of cash required or retained for debt service or repayment
- amounts required to fund capital expenditures and working capital requirements
- access to equity markets
- foreign currency exchange rates and interest rates
- the risk factors set forth in this Annual Information Form

The decision whether 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.

In addition, to the extent the Corporation uses internally-generated cash flow to repurchase shares, or 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 may 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, or repurchase shares from 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.

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

The price that the Corporation receives for a majority of its oil and natural gas is based on U.S.-dollar denominated benchmarks and, therefore, the price that the Corporation receives in Canadian dollars is affected by the exchange rate between the two currencies. Should there be a material increase in the value of the Canadian dollar relative to the U.S. dollar, it may negatively impact the Corporation's net production revenue by decreasing the Canadian dollars the Corporation receives for a given sale in U.S. dollars. The Corporation’s business and operations in Canada and the United States have contracts that are linked to the U.S. dollar and, therefore, the Corporation is exposed to foreign currency risk on both revenues and costs. In addition, the Corporation has U.S.-dollar denominated Senior Unsecured Notes and is exposed to increased foreign currency risk should the Canadian dollar weaken against the U.S. dollar. The Corporation may from time to time use derivative instruments to manage a portion of its foreign exchange risk, as described in Note 14(c) to the Corporation's Financial Statements.

Recent court rulings on the liability surrounding abandonment and reclamation obligations of oil and gas companies may adversely affect the Corporation.

As a general rule, the current oil and gas asset abandonment, reclamation and remediation ("**A&R**") liability regime in Alberta limits each party's liability to its proportionate ownership of an asset. In the case where one joint owner of an oil and gas asset becomes insolvent and is unable to fund the required A&R activities associated with such asset, the solvent counterparties can recover the insolvent party's share of the remediation costs from the Orphan Well Association (the "**OWA**"). The OWA administers orphaned assets and is funded through a levy imposed on licensees, including the Corporation, based on their proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta. British Columbia has similar liability management regimes.

As a result of the Supreme Court of Canada's January 2019 decision in the case of Redwater Energy Corporation ("**Redwater**"), a trustee in bankruptcy is not permitted to renounce uneconomic oil and gas assets and leave these assets to be remediated by the OWA, thereby avoiding the environmental liabilities of the estate it is administering. Accordingly, the AER may now use Alberta’s provincial legislative scheme to prevent the repudiation or renunciation of an insolvent company's assets by a trustee and require the trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors.

In response to lower court decisions relating to Redwater, the AER released Bulletin 2016-16 which, among other things, implemented important changes to the AER's procedures relating to liability management ratings, licence eligibility and licence transfers. In addition, changes with respect to licence eligibility were codified in amendments to AER Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals. Among other things, Directive 067 provides the AER with broad discretion to determine if a party poses an "unreasonable risk" such that it should not be eligible to hold AER licences.

The British Columbia provincial government has announced similar policies. The BCOGC is also exploring the development of a comprehensive liability management strategy driven in part by the proliferation of orphan sites. The imposition of timelines for cleanup of inactive sites is among the measures under consideration.

These changes may impact the Corporation's ability to transfer its licences, approvals or permits in the course of a divestment, and may result in increased costs and delays or require changes to or abandonment of projects and transactions. As a result of the decision in Redwater, lenders may reduce the availability of credit to oil and gas issuers that utilize secured loans, thereby negatively affecting the financial capacity of such issuers, including potential partners and counterparties of the Corporation. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Corporation, and the associated A&R liabilities in determining whether to provide credit, may require borrowers to adhere to more stringent A&R-related operational covenants, and may increase the cost of providing credit.

The Supreme Court decision in Redwater also could make the transfer of oil and gas assets from insolvent parties more challenging if a trustee in bankruptcy is unable to separate economic assets from uneconomic assets within the insolvent party's estate in order to facilitate a sale process. The result could be additional liabilities being placed upon the OWA. The OWA may seek funding for such liabilities from industry participants, including the Corporation, through an increase in its annual levy, further changes to regulations, or other means. While the impact on the Corporation of any legislative, regulatory or policy decisions as a result of the Redwater decision cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact the Corporation and materially and adversely affect, among other things, the Corporation's business, financial condition, results of operations and cash flow.

Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief.

Declines or continued volatility in crude oil and natural gas prices may result in a significant reduction in earnings or cash flow, which could lead the Corporation to increase amounts drawn under the Bank Credit Facility in order to carry out its operations and fulfill its obligations. Significant reductions to cash flow, significant increases in drawn amounts under the Bank Credit Facility, or significant reductions to proved reserves may result in the Corporation breaching its debt covenants under the Credit Facilities. If a breach occurs, there is a risk that the Corporation may not be able to negotiate covenant relief with one or more of its lenders under the Credit Facilities. Failure to comply with debt covenants or negotiate relief may result in the Corporation's indebtedness under the Credit Facilities becoming immediately due and payable, which may have a material adverse effect on the Corporation's operations and financial condition.

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

Although the Corporation believes that its existing Credit Facilities are sufficient, there can be no assurance that the current amount will continue to be available or will be adequate for the financial obligations of the Corporation or that additional funds can be obtained as required or on terms which are economically advantageous to the Corporation. The amounts available under the Credit Facilities may not be sufficient for future operations, or the Corporation may not be able to renew its Bank Credit Facility or obtain additional financing on attractive economic terms, if at all. The Bank Credit Facility is generally available on a three-year term, extendable each year with a bullet payment required at the end of three years if the facility is not renewed. The Corporation renewed its Bank Credit Facility in 2018 and, accordingly, it currently expires on October 31, 2021. 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 by the Corporation to obtain replacement financing or financing on favourable terms, may have a material adverse effect on the Corporation's business and operations. In addition, dividends to shareholders may be eliminated, as repayment of debt under the Credit Facilities has priority over dividend payments by the Corporation to its shareholders.

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

The Corporation's business and operations, including the drilling of oil and natural gas wells and the production and transportation of oil and natural gas, are subject to certain risks inherent in the oil and natural gas business. These risks and hazards include encountering unexpected formations or pressures, blow-outs, pipeline breaks, rail transportation incidents, craterings, fires, power interruptions and severe weather conditions. The Corporation's operations may also subject it to the risk of vandalism or terrorist threats, including eco-terrorism and cyber-attacks. 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. The Corporation may become liable for damages arising from events against which it cannot insure, or against which it may elect not to insure because of high premium costs, or other reasons. While the Corporation has both safety and environmental policies in place to protect its operators and employees, and to meet regulatory requirements in areas where they operate, any costs incurred to repair, damage, or pay liabilities would adversely affect the Corporation's financial position, including the amount of funds that may be available for development programs, debt repayments, or dividend payments to shareholders.

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

The Corporation’s business and prospects for future success, including the successful implementation of strategies and/or handling of issues integral to its future success, depend to a significant extent upon the continued service and performance of the management team and key personnel. Shareholders are entirely dependent on the management and key personnel of the Corporation with respect to the exploration for and development of additional reserves and resources, the acquisition of oil and natural gas properties and assets, and the management and administration of all matters relating to the Corporation and its properties and assets, including hiring competent personnel. The loss of any member of Enerplus’ management team or other key personnel, and its inability to attract, motivate and retain substitute key personnel with comparable experience and skills, could materially and adversely affect the business, financial condition and results of operations.

The increased acceptance of new technology may lead to reputational issues or financial losses.

Technologies are often employed to assist, augment, automate or provide autonomous intelligence, which results in reduced reliance on human intervention and/or decision-making and, therefore, may increase the Corporation’s risk of financial or reputational loss.

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 other companies involved in the oil and gas industry which are in competition to the interests of the Corporation. See "*Directors and Officers – Conflicts of Interest*".

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

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

Market for Securities

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

The following table sets forth certain trading information for the Common Shares on the TSX composite index and the United States composite index for 2018.

	TSX Composite Trading			U.S. Composite Trading		
Month	**High**	**Low**	**Volume**	**High**	**Low**	**Volume**
January	14.54	12.20	50,163,913	11.78	9.82	31,326,187
February	15.06	12.18	46,248,019	11.87	9.66	20,634,975
March	15.90	13.53	41,559,946	12.26	10.49	18,399,673
April	16.01	13.79	52,005,269	12.47	10.75	20,608,654
May	17.21	14.50	49,304,900	13.49	11.26	23,424,071
June	17.07	15.12	41,199,968	12.95	11.42	23,748,745
July	17.73	16.30	28,924,564	13.56	12.21	14,291,252
August	18.04	15.95	36,067,423	13.87	12.11	14,265,185
September	16.39	14.51	34,761,331	12.65	11.03	12,314,492
October	16.57	11.68	57,356,810	12.89	8.90	18,273,901
November	13.37	11.92	51,942,963	9.99	9.03	22,010,746
December	13.70	9.65	44,130,960	10.40	6.84	26,460,947

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 and principal occupation for the past five years for each current director of the Corporation are set forth below.

Name and Residence	Director Since	Principal Occupation for Past Five Years
Elliott Pew(1) Boerne, Texas, United States	September 2010	Corporate director.
Karen E. Clarke-Whistler(3)(6) Toronto, Ontario, Canada	December 2018	Corporate director. Prior thereto, Chief Environment Officer at TD Bank Group until her retirement in 2018.
Michael R. Culbert(2)(3)(4) Calgary, Alberta, Canada	March 2014	Mr. Culbert is Vice Chairman of Petronas Energy Canada Ltd. ("Petronas Canada"), an oil and gas company, since November 2016. He continues to serve as a non-executive director of Petronas Canada and Precision Drilling Corporation (an oilfield services company). Prior thereto, he was President and Chief Executive Officer of Petronas Canada.
Ian C. Dundas Calgary, Alberta, Canada	July 2013	President & Chief Executive Officer of Enerplus since July 2013. Prior thereto, Executive Vice President and Chief Operating Officer of Enerplus from April 2011 to July 2013.
Hilary A. Foulkes(3)(4)(5)(6)(8) Calgary, Alberta, Canada	February 2014	Corporate director. Currently Chair, Tudor, Pickering, Holt & Co. Securities – Canada, ULC.
Robert B. Hodgins(2)(3)(4)(7) Calgary, Alberta, Canada	November 2007	Mr. Hodgins is a Senior Advisor, Investment Banking at Canaccord Genuity Corp. since September 2018 and has been an independent businessman since November 2004.
Susan M. MacKenzie(2)(5)(6) Calgary, Alberta, Canada	July 2011	Corporate director. Prior thereto, independent consultant from 2010 to 2015.
Glen D. Roane(2)(3)(9) Canmore, Alberta, Canada	June 2004	Corporate director.
Jeffrey W. Sheets(2)(4)(6) Houston, Texas, United States	December 2017	Corporate director. Prior thereto, Executive Vice President and Chief Financial Officer of ConocoPhilips Company from October 2010 to February 2016.
Sheldon B. Steeves(5)(6) Calgary, Alberta, Canada	June 2012	Corporate director.

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 Chair, Michael R. Culbert, Susan M. MacKenzie, Glen D. Roane, and Jeffrey W. Sheets.
(3) The Corporate Governance & Nominating Committee is currently comprised of Glen D. Roane as Chair, Michael R. Culbert, Karen E. Clarke-Whistler, Hilary A. Foulkes and Robert B. Hodgins.
(4) The Compensation & Human Resources Committee is currently comprised of Michael R. Culbert as Chair, Hilary A. Foulkes, Robert B. Hodgins and Jeffrey W. Sheets.
(5) The Reserves Committee is currently comprised of Sheldon B. Steeves as Chair, Hilary A. Foulkes and Susan M. MacKenzie.
(6) The Safety & Social Responsibility Committee is currently comprised of Susan M. MacKenzie as Chair, Karen E. Clarke-Whistler, Hilary A. Foulkes, Jeffrey W. Sheets and Sheldon B. Steeves.
(7) Mr. Hodgins was a director of Skope Energy Inc. ("Skope") from December 15, 2010 to February 19, 2013. On November 27, 2012, Skope was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the CCAA to implement a restructuring which was approved by the required majority of Skope's creditors. The restructuring was sanctioned by the Court of Queen's Bench of Alberta in February of 2013.
(8) Ms. Foulkes was a director of Parallel Energy Trust ("Parallel"). On November 9, 2015, Parallel and its affiliated entities filed an application for protection under the CCAA and voluntary petitions for relief under *Chapter 11 of Title 11 of the United States Code* in the United States Bankruptcy Court of Delaware. Ms. Foulkes ceased to be a director of Parallel on March 1, 2016. Parallel filed an assignment in bankruptcy and proceedings under the CCAA were terminated in March 2016.
(9) Mr. Roane will not be standing for re-election at the Annual Meeting to be held on May 9, 2019.

OFFICERS OF THE CORPORATION

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

Name and Residence	Office	Principal Occupation for Past Five Years
Ian C. Dundas Calgary, Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of the Corporation.
Jodine J. Jenson Labrie Calgary, Alberta, Canada	Senior Vice President & Chief Financial Officer	Senior Vice President & Chief Financial Officer of the Corporation since September 2015. Prior thereto, Vice President, Finance of the Corporation since July 2013.
Raymond J. Daniels Calgary, Alberta, Canada	Senior Vice President, Operations, People & Culture	Senior Vice President, Operations, People & Culture of the Corporation since January 2017. Prior thereto, Senior Vice President, Operations of the Corporation.
Garth R. Doll Calgary, Alberta, Canada	Vice President, Marketing	Vice President, Marketing of the Corporation since February 2019. Prior thereto, Manager, Marketing of the Corporation since 2013.
Terry S. Eichinger Calgary, Alberta, Canada	Vice President, U.S. Operations & Engineering	Vice President, U.S. Operations & Engineering of the Corporation since September 2018. Prior thereto, Senior Manager, U.S. Operations & Engineering of the Corporation since May 2014 and Manager, Deep Gas of the Corporation since May 2011.
Nathan D. Fisher Denver, Colorado, United States	Vice President, U.S. Development & Geosciences	Vice President, U.S. Development & Geosciences of the Corporation since September 2015. Prior thereto, Manager, Geology & Geophysics for U.S. Operations of the Corporation since April 2011.
Daniel J. Fitzgerald Calgary, Alberta, Canada	Vice President, Business Development	Vice President, Business Development of the Corporation since September 2015. Prior thereto, Manager, Business Development & Strategic Planning of the Corporation.
John E. Hoffman Calgary, Alberta, Canada	Vice President, Canadian Operations	Vice President, Canadian Operations of the Corporation since April 2015. Prior thereto, General Manager, North America Onshore at Suncor Energy Inc.
David A. McCoy Calgary, Alberta, Canada	Vice President, General Counsel & Corporate Secretary	Vice President, General Counsel & Corporate Secretary of the Corporation.
Edward L. McLaughlin Denver, Colorado, United States	President, U.S. Operations	President, U.S. Operations of the Corporation.
Shaina B. Morihira Calgary, Alberta, Canada	Vice President, Finance	Vice President, Finance of the Corporation since February 2018. Prior thereto, Corporate Controller of the Corporation since July 2015. Prior thereto, Controller, Financial of Progress Energy Canada Ltd. from January 2015 to July 2015. Prior thereto, Manager, Financial Reporting of Progress Energy.

COMMON SHARE OWNERSHIP

As of February 20, 2019, the directors and officers of the Corporation named above beneficially own, or control or exercise direction over, directly or indirectly, an aggregate of 858,747 Common Shares, representing approximately 0.4% 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 or other companies which are in competition with the Corporation, and as such may encounter conflicts of interest 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 operations or liquidity. Notwithstanding the above, the Corporation is aware of a class action filed in Fort Berthold Tribal Court in November 2017 as Civil Action No. 2017-0505 against the Corporation and fifteen other companies operating on the FBIR (the "Action"). The plaintiffs in the Action are members of the Three Affiliated Tribes who own mineral interests on the FBIR and allege that the defendant companies have committed trespass, failed to pay royalties properly, etc. They seek judgement against the defendant group for $585 million in damages, $500 million in punitive damages, and disgorgement of the value of oil and gas produced from the plaintiffs' property. The Corporation believes the claim, as against the Corporation, is without merit.

Interest of Management and Others in Material Transactions

To the knowledge of the directors and executive officers of the Corporation, none of the directors or executive officers of the Corporation and no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of the Corporation's securities, nor any associate or affiliate of any of the foregoing, has had any material interest, direct or indirect, in any transaction with the Corporation since January 1, 2016 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 in the normal course of business and relating to the Credit Facilities have been filed on the Fund's SEDAR profile at www.sedar.com and on Form 6-K on the Fund's EDGAR profile at www.sec.gov, if they were filed prior to the January 1, 2011 Conversion, and on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov, if they were filed on or after the January 1, 2011 Conversion:

1. Amended and Restated Bank Credit Facility (November 5, 2012); the First Amending Agreement relating thereto (January 13, 2014); the Second Amending Agreement relating thereto (May 13, 2014); the Third Amending Agreement relating thereto (SEDAR – December 1, 2014; EDGAR – December 9, 2014); the Fourth Amending Agreement relating thereto (November 6, 2015); the Fifth Amending Agreement relating thereto (November 7, 2016); and the Sixth Amending Agreement relating thereto (November 8, 2018);

2. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2009 (SEDAR – June 23, 2009; EDGAR – June 25, 2009);

3. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2012 (SEDAR – May 23, 2012; EDGAR – May 24, 2012); and

4. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2014 (SEDAR – October 10, 2014; EDGAR – October 15, 2014).

Copies of the following documents affecting the rights of securityholders have been filed on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov.

1. the Articles of Amalgamation (January 2, 2013); By-law No. 1 of the Corporation (June 16, 2014); and By-law No. 2 of the Corporation (May 6, 2016); and

2. the Shareholder Rights Plan, as described under "Description of Capital Structure – Shareholder Rights Plan" (May 6, 2016).

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 internal estimates of contingent resources attributable to the Corporation's interests in the Fort Berthold, North Dakota area, and certain of its waterflood assets located in Alberta and Saskatchewan, which are referred to in this Annual Information Form in Appendix A. 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, no outstanding Common Shares. NSAI prepared the NSAI Report in respect of the reserves and contingent resources attributable to the Corporation's interests in the Marcellus property, a summary of which is contained in this Annual Information Form. As of the dates of the NSAI Report, the designated professionals of NSAI, as a group, beneficially owned, directly or indirectly, no outstanding Common Shares.

KPMG LLP ("**KPMG**") was appointed as the auditors of the Corporation on May 31, 2017 and have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations, and also that they are independent accountants with respect to the Corporation under all relevant U.S. professional and regulatory standards. Deloitte LLP ("**Deloitte**") was the independent registered public accounting firm of the Corporation for the years ended December 31, 2016. Throughout the periods covered by the financial statements of the Corporation on which they reported, Deloitte was independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules and standards of the Public Company Accounting Oversight Board and the securities laws and regulations administered by the SEC.

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 2019 annual meeting of shareholders. Furthermore, additional financial information relating to the Corporation is provided in the Corporation's audited consolidated financial statements and MD&A. Shareholders who wish to receive printed copies of these documents free of charge should contact the Corporation's Investor Relations Department using the contact information on the back cover of this Annual Information Form.

APPENDIX A

Appendix A – Contingent Resources Information

NOTE TO READER REGARDING DISCLOSURE OF CONTINGENT RESOURCES INFORMATION

All of the Corporation's contingent resources have been evaluated in accordance with NI 51-101. NSAI, an independent petroleum consulting firm based in Dallas, Texas, has evaluated the Corporation's contingent resources attributable to its Marcellus properties located in Pennsylvania, United States, using the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2019. The Corporation has evaluated the balance of its U.S. properties located in North Dakota, United States, and its Canadian properties located in Alberta and Saskatchewan to which contingent resources have been assigned using similar evaluation parameters, including the same forecast price, inflation and exchange rate assumptions utilized by McDaniel, which as required by NI 51-101 has audited the Corporation's internal evaluation of these properties.

The following sections and tables summarize, as at December 31, 2018, the Corporation's "best estimate" (as defined below) contingent resources, including risked contingent resource volumes and risked net present value of future net revenue of contingent resources in development pending project maturity sub-class, together with certain information, estimates and assumptions associated with such 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.

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

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

The estimated future net revenue to be derived from the production of the contingent resources set out in this Appendix A is based on the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2019, and was utilized by NSAI and by the Corporation in its internal evaluations for consistency in the Corporation's reporting, and the inflation and exchange rate assumptions set forth under "*Oil and Natural Gas Reserves – Forecast Prices and Costs*" in the Annual Information Form. Also see "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information – Description of Price and Cost Assumptions*" in the Annual Information Form.

It should not be assumed that the summary of risked net present value of estimated future cash flows shown in the tables below is representative of the fair market value of the contingent resources. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and contingent resources estimates of the Corporation's crude oil, natural gas liquids and natural gas contingent resources provided herein are estimates only. Actual resources may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained below.

Contingent Resources Categories and Levels of Certainty for Reported Resources

In this Appendix A, the Corporation has disclosed estimated volumes of economic "contingent resources" which relate to the Corporation's interests in its Fort Berthold property located in North Dakota, its Marcellus shale gas property located in Pennsylvania, and certain of its crude oil properties located in Alberta and Saskatchewan.

"**resources**" are petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced.

"**contingent resources**" are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are economically recoverable based on the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2019.

The economic contingent resources estimates in this Appendix A 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”.

"**risked**" means that the applicable volumes or revenues have been adjusted for the probability of loss or failure in accordance with the COGEH. See "*Description of Properties*" below.

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

Contingent Resources Development Status

Contingent resources may be divided into the following project maturity sub-classes:

"**development pending**" resources sub-class is assigned to contingent resources for a particular project where resolution of the final conditions for development is being actively pursued (there is a high chance of development) and the project is expected to be developed in a reasonable timeframe;

"**development on hold"** resources sub-class is assigned to contingent resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator;

"**development unclarified**" resources are those for which additional information is being acquired;

"**development not viable**" resources are those where no further data acquisition or evaluation is currently planned and there is a low chance of development.

All of the Corporation's contingent resources fall into the "development pending" sub-class.

CONTINGENT RESOURCES DATA

The following tables set forth the "best estimate" of gross and net risked contingent resources volumes and risked net present value of future net revenue attributable to the Corporation's contingent resources in the development pending project maturity sub-class, at December 31, 2018, using forecast price and cost cases. **An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Corporation proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is no certainty that the estimate of risked net present value of future net revenue will be realized.**

Summary of Risked Oil and Gas
Contingent Resources (Forecast Prices and Costs)
As of December 31, 2018

	CONTINGENT RESOURCES													
PROJECT MATURITY SUB-CLASS	**Light & Medium Oil**		**Heavy Oil**		**Tight Oil**		**Natural Gas Liquids**		**Conventional Natural Gas**		**Shale Gas**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)
Development Pending	2,861	2,467	22,325	18,971	53,088	42,473	5,862	4,690	777	672	589,076	471,262	182,446	147,257

Risked Net Present Value of Future Net Revenue
Contingent Resources (Forecast Prices and Costs)
As of December 31, 2018

	RISKED NET PRESENT VALUE OF FUTURE NET REVENUE DISCOUNTED AT (%/Year)				
	Before Deducting Income Taxes				
PROJECT MATURITY SUB-CLASS	**0%**	**5%**	**10%**	**15%**	**20%**
	(in $ millions)				
Development Pending	3,611.1	1,722.7	910.1	514.3	299.9

DESCRIPTION OF PROPERTIES

Outlined below is a description of the Corporation's "best estimate" of economic contingent resources for its Canadian and U.S. crude oil and natural gas properties and assets. There is no certainty it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources".

Canadian Crude Oil Properties

The Corporation has conducted an internal evaluation of the contingent resources associated with a portion of its crude oil waterflood properties which has resulted in an unrisked "best estimate" of 31.6 MMBOE (25.3 MMBOE risked) being classified as economic contingent resources effective as of December 31, 2018. The unrisked net present value of future net revenue, discounted at 10%, of these contingent resources is $303.5 million ($242.8 million risked). This internal evaluation has been independently audited by McDaniel. Improved oil recovery from four existing waterfloods through optimization work accounts for approximately 11.1 MMBOE of the total volumes, 7.6 MMBOE from areas producing heavy crude oil and 3.6 MMBOE from areas producing light or medium crude oil. Approximately 20.4 MMBOE of the total is attributable to heavy crude oil EOR projects in the Corporation's Giltedge property and the Medicine Hat Glauconitic "C" East Unit where polymer flood projects are underway. To implement the projects to recover the contingent resources, it is estimated that $629.1 million of capital will be required. For the improved oil recovery projects, this capital will be spent from 2020 to 2026, and from 2019 to 2045 for the EOR polymer flood projects. As work proceeds and assessed results continue to support the economic viability of these projects, each year a portion of contingent resources is anticipated to be reclassified as reserves. Although further EOR projects are being contemplated on certain of the Corporation's other Canadian crude oil properties, these have not been fully evaluated and no contingent resources have been assessed.

Significant positive factors embedded in this estimate include well-established waterflood technology, a long history of waterflood performance data and success with the EOR projects that have been implemented. 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. These resources are all classified into "development pending" project maturity sub-class as the Corporation is actively pursuing these projects. The chance of development is estimated to be 80% for the waterflood contingent resources based on the favourable results to date and the slight variability of the reservoirs. The contingency preventing these resources from being classified as reserves is the early stage of implementation to the specific waterfloods and the lack of internal approvals for full field implementation. There are several inherent risks and contingencies associated with the development of these properties, including the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, acquisitions, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in the Annual Information Form.

U.S. Crude Oil Properties

An evaluation of the Corporation's interests in the Bakken and Three Forks formations at Fort Berthold, North Dakota conducted internally by the Corporation and audited by McDaniel has attributed an unrisked "best estimate" of 70.9 MMBOE (63.8 MMBOE risked) of economic contingent resources attributable to these formations, effective as of December 31, 2018, a decrease of approximately 10% from the estimate as of December 31, 2017. The decrease compared to 2017 was the result of 12.5 MMBOE of unrisked contingent resources being converted to undeveloped reserves, offset by positive revisions to previous estimates of 4.2 MMBOE unrisked contingent resources. The recovery of these tight oil contingent resources is under a primary solution gas drive through horizontal wells completed with multiple fracture treatments. These contingent resources represent approximately 135.6 net future drilling locations over and above 130.2 net booked drilling locations identified in the Corporation's booked proved plus probable reserves. The capital required to drill these locations is estimated to be US$1,157.8 million (or CDN$1,435.2 million) between 2022 and 2025. These estimates are based primarily upon a drilling density of up to 10 wells per drilling spacing unit in the Bakken and Three Forks formations combined. The contingent resources average expected ultimate recovery per well is estimated at 535 MBOE. These contingent resources are economic using established technologies and under current forecast commodity prices. Given the drilling density to date, these contingent resources represent a non-reserve land utilization of 100% for the operated lands. All of these contingent resources are classified into "development pending" project maturity sub-class, with an estimated chance of development of 90% as their development is expected to immediately follow the reserves development. After application of the chance of development, the risked NPV discounted at 10% is CDN$408.0 million. The Corporation has approximately 194 net reserves wells currently on production in this area.

The primary contingencies which currently prevent the classification of the Corporation's disclosed contingent resources associated with the Fort Berthold, North Dakota property as reserves consist of i) a lack of corporate approval for development, and ii) undeveloped reserves. Significant positive factors related to the estimate include continued advancement of drilling and completion technology, and performance of producing wells that continues to exceed expectations resulting in positive revisions to reserves. Another factor related to the estimate is the limited long-term performance history in the immediate area of the contingent resources. There are a number of inherent risks and contingencies associated with the development of the interests in the property including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on industry partners in project development, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in the Annual Information Form.

U.S. Natural Gas Properties

NSAI has conducted an independent assessment of the contingent resources attributable to the Corporation's interests in the Marcellus property and has provided an unrisked "best estimate" of economic shale gas contingent resources of approximately 699.7 Bcf (559.8 Bcf risked) at December 31, 2018. The unrisked NPV associated with these contingent resources is CDN$324.1 million (CDN$259.3 million risked). Approximately 129.6 Bcf of contingent resources were reclassified as reserves in 2018. The remaining contingent resources are economic based on the forecast price and cost assumptions used for the Corporation's year-end 2018 reserves evaluations. This estimate represents a non-reserve land utilization rate of 95% and average well ultimate recovery of approximately 13.1 Bcf. These contingent resources are classified into "development pending" project maturity sub-class as it is anticipated their development will be a continuation of the current reserves development. These contingent resources have an estimated 80% chance of development. It is also estimated that US$359.2 million (or CDN$444.6 million) of capital will be required to develop these contingent resources with multifractured horizontal wells, and development will occur from 2024 to 2030. The primary contingencies which currently prevent the classification of the Corporation's disclosed contingent resources associated with its Marcellus interests as reserves consist of additional delineation drilling to confirm economic productivity in the immediate vicinity of the development areas, limitations to development based on adverse topography or other surface restrictions, the uncertainty regarding marketing and transportation of natural gas from development areas, the receipt of all required regulatory permits and approvals to develop the land, and limited access to confidential information of other operators in the Marcellus formation that would support the recognition of reserves on the Corporation's areas of interest. Significant negative factors related to the estimate include the following: 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 property 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, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in the Annual Information Form.

APPENDIX B

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

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

1. We have audited, evaluated and reviewed, as applicable, the Corporation's reserves data and contingent resources data as at December 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2018, estimated using forecast prices and costs.

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

3. We carried out our audit, evaluation and review, as applicable, in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table sets forth the net present value of 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 Corporation evaluated and reviewed for the year ended December 31, 2018, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation or Review Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (in $ thousands)			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	December 31, 2018	Canada	-	$ 503,295.6	$ 217,509.0	$ 720,804.6
McDaniel & Associates Consultants Ltd.	December 31, 2018	North Dakota, Montana & Colorado, USA	-	US$ 2,416,815.2 (1)	-	US$ 2,416,815.2
Netherland, Sewell & Associates, Inc.	December 31, 2018	Pennsylvania, USA	-	US$ 678,799.0 (1)	-	US$ 678,799.0
TOTALS				$ 4,364,593.6	$ 217,509.0	$ 4,582,102.6

(1) Future net revenue in $US was converted to $Cdn using the average of the forecast exchange rates of GLJ, McDaniel and Sproule as of January 1, 2019. These are: 0.757 for 2019, 0.782 for 2020, 0.797 for 2021, 0.803 for 2022, 0.807 for 2023 and 0.808 thereafter.

6. The following table sets forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Corporation's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources that we have audited and evaluated and reported on to the Corporation's management:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Audit or Evaluation Report	Location of Resources Other than Reserves	Risked Volume (MMBOE)	Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (in $ thousands)		
					Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	McDaniel & Associates Consultants Ltd.	December 31, 2018	Canada	25.3	$ 242,769.0	$ -	$ 242,769.0
Development Pending Contingent Resources (2C)	McDaniel & Associates Consultants Ltd.	December 31, 2018	North Dakota, USA	63.8	$US 330,218.8	$ -	$US 330,218.8
Development Pending Contingent Resources (2C)	Netherland, Sewell & Associates, Inc.	December 31, 2018	Pennsylvania, USA	93.3	$ -	$US 209,531.1	$US 209,531.1

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

8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the respective effective dates of our reports.

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

10. Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by B. Hamm"

B. Hamm, P.Eng.
President & Managing Director

Calgary, Alberta, Canada

February 21, 2019

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

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

Texas Registered Engineering Firm F-2699
Dallas, Texas, USA

February 21, 2019

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") is 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 and contingent resources data.

Independent qualified reserves evaluators have evaluated, reviewed and audited, as applicable, the Corporation's reserves data and contingent resources data. The report of the independent qualified reserves evaluators is presented as Appendix 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 and contingent resources 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, contingent resources data and other oil and gas information

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

(c) the content and filing of this report

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

ENERPLUS CORPORATION

"*Ian C. Dundas*"
Ian C. Dundas
President & Chief Executive Officer

"*John E. Hoffman*"
John E. Hoffman
Vice President, Canadian Operations

"*Elliott Pew*"
Elliott Pew
Director

"*Sheldon B. Steeves*"
Sheldon B. Steeves
Director

February 22, 2019

APPENDIX D

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 included in this Appendix D.

B. COMPOSITION OF THE AUDIT & RISK MANAGEMENT COMMITTEE

The current members of the Committee are Robert B. Hodgins (Chairman), Michael. R. Culbert, Susan M. MacKenzie, Glen D. Roane and Jeffrey W. Sheets. Each member of the Committee is independent and financially literate within the meaning of National Instrument 52-110. Mr. Roane will not be standing for re-election as a director of the Corporation at the annual meeting of the Corporation's shareholders to be held on May 9, 2019.

C. RELEVANT EDUCATION AND EXPERIENCE

Name (Director Since)	Principal Occupation and Biography
Robert B. Hodgins (Honors B.A. (Business), CPA, CA) (Director since November 2007) Other Public Directorships • AltaGas Ltd. (energy midstream services) • Gran Tierra Energy Inc. (international oil and gas exploration and production company) • MEG Energy Corp. (oil sands company)	Mr. Hodgins is a Senior Advisor, Investment Banking at Canaccord Genuity Corp. since September 2018 and 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.
Michael R. Culbert (B.Sc. (Business Administration)) (Director since February 2014) Other Public Directorships • Precision Drilling Corporation	Mr. Culbert is Vice Chairman of Petronas Energy Canada Ltd. ("Petronas Canada"), an oil and gas company, since November 2016. He continues to serve as a director on the boards of Petronas Canada in a non-executive capacity and Precision Drilling Corporation (an oilfield services company). Prior thereto, he was President and Chief Executive Officer of Petronas Canada.

Name (Director Since)	Principal Occupation and Biography
Susan M. MacKenzie (B. Eng. (Mechanical), MBA) (Director since July 2011) <u>Other Public Directorships</u> • Freehold Royalties Ltd. (oil and gas royalty focused company) • Precision Drilling Corporation (oil and gas services company) • TransGlobe Energy Corporation (oil and gas company)	Ms. MacKenzie has over 26 years of energy sector experience, most recently serving as Chief Operating Officer with Oilsands Quest Inc. in 2010, and currently serves as a director of Enerplus, Freehold Royalties Ltd., a Canadian oil and gas royalty focused company, Precision Drilling Corporation, an oil and gas services company, and TransGlobe Energy Corporation, a Canadian oil and gas company. Prior to that, Ms. Mackenzie enjoyed a 12-year career at Petro-Canada where she held senior roles including Vice-President of Human Resources and Vice President of In Situ Development & Operations. Ms. MacKenzie was also with Amoco Canada for 14 years in a variety of engineering and leadership roles in natural gas, conventional oil and heavy oil exploitation. Ms. MacKenzie is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA) and holds the ICD.D. designation from the Institute of Corporate Directors.
Glen D. Roane (B.A., MBA) (Director since June 2004) <u>Other Public Directorships</u> • Badger Daylighting Ltd. (provider of non-destructive excavation services) • Crown Capital Partners, Inc. (financing company)	Mr. Roane is a corporate director and currently serves as a director of Enerplus, Badger Daylighting Ltd., and Crown Capital Partners, Inc. Previously, he served as a board member of a number of TSX-listed energy/resources companies. Mr. Roane also served two terms as a Member of the Alberta Securities Commission. Mr. Roane retired from TD Asset Management Inc., a subsidiary of the Toronto-Dominion Bank in 1997. Mr. Roane is a director of GBC American Growth Fund Inc., a Canadian mutual fund corporation. Mr. Roane holds a Bachelor of Arts and an MBA from Queen's University in Kingston, Ontario and also holds the ICD.D designation from the Institute of Corporate Directors.
Jeffrey W. Sheets (B.Sc. (Chemical Engineering), MBA (Finance)) (Director since December 2017) <u>Other Public Directorships</u> • Westlake Chemical Corporation (chemicals and plastics sales and manufacturing)	Mr. Sheets served as executive vice president and chief financial officer of ConocoPhillips Company from October 2010 to February 2016. Mr. Sheets was associated with ConocoPhillips and its predecessor companies for more than 36 years and served in a variety of roles, including senior vice president of planning and strategy as well as vice president and treasurer. He began his career in 1980 as a process engineer with Phillips Petroleum Company. Mr. Sheets also serves on the board of directors of Westlake Chemical Corporation and is a former director of DCP Midstream Partners LP. Mr. Sheets received a bachelor's degree in chemical engineering from the Missouri University of Science and Technology and an MBA from the University of Houston. Mr. Sheets is a member of the Board of Trustees at the Missouri University of Science and Technology.

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 KPMG and Deloitte in 2018 and 2017 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 KPMG and Deloitte described above is compatible with maintaining that firm's independence from the Corporation.

E. EXTERNAL AUDITOR SERVICE FEES

The aggregate fees paid by the Corporation to KPMG (after May 31, 2017) and Deloitte (before May 31, 2017), each an Independent Registered Public Accounting Firm, and the independent auditors of Enerplus at relevant times, for professional services rendered in Enerplus' last two fiscal years are as follows:

		2018	2017
		(in $ thousands)	
Audit fees(1)	Deloitte	$ -	$ 137.5
	KPMG	$ 662.0	$ 605.0
Audit-related fees(2)	Deloitte	-	-
	KPMG	-	-
Tax fees(3)	Deloitte		64.5
	KPMG	43.1	61.3
All other fees(4)	Deloitte	-	-
	KPMG	-	15.2
Total	**Deloitte**	**$ -**	**$ 202.0**
	KPMG	**$ 705.1**	**$ 681.5**

Notes:

(1) Audit fees in 2018 were for professional services rendered by KPMG for the audit of the Corporation's annual financial statements and review of the Corporation's quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees are for assurance and related services provided by KPMG reasonably related to the performance of the audit or review of the Corporation’s financial statements and not reported under “Audit fees” above.

(3) Tax fees in 2018 were for tax compliance, tax advice and tax planning by KPMG.

(4) All other fees in 2018 related to products and services provided by KPMG other than those described as "Audit fees" and "Tax fees". For 2017, other fees include French translation services.

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 Chair of the Committee shall be designated by the Board, provided that if the Board does not so designate a Chair, the members of the Committee, by majority vote, may designate a Chair. The presence in person or by telephone of a majority of the Committee's members shall constitute a quorum for any meeting of the Committee. All actions of the Committee will require the vote of a majority of its members present at a meeting of the Committee at which a quorum is present.

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

II. PURPOSE OF THE COMMITTEE

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

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

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

III. COMPOSITION AND COMPETENCY OF THE COMMITTEE

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

IV. MEETINGS OF THE COMMITTEE

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

V. DUTIES AND ACTIVITIES OF THE COMMITTEE

Evaluating and monitoring the performance and independence of external auditors

1. Make recommendations to the Board on the appointment of external auditors of the Corporation

2. Review and approve the Corporation's external auditors' annual engagement letter, including the proposed fees contained therein

3. Review the performance of the external auditors and make recommendations to the Board regarding their replacement when circumstances warrant. The review shall take into consideration the evaluation made by management of the external auditors' performance and shall include:

   a) review annually the external auditors' quality control, any material issues raised by the most recent quality control review, or peer review, of the firm, or any inquiry or investigation by governmental or professional authorities of the firm within the preceding five years, and any steps taken to deal with such issues

   b) obtain assurances from the external auditors that the audit was conducted in accordance with Canadian and U.S. generally accepted auditing standards and

   c) ensure that management interacts professionally with the auditors and confirm such behavior annually with both parties

4. Oversee the independence of the external auditors by, among other things:

   a) requiring the external auditors to deliver to the Committee on a periodic basis a formal written statement detailing all relationships between the external auditors and the Corporation

   b) reviewing and approving the Corporation's hiring policies regarding partners, employees and former partners and employees of current and former external auditors

   c) actively engaging in a dialogue with the external auditors with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditors and recommending that the Board take appropriate action to satisfy itself of the auditors' independence

   d) pre-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 Chair of the Committee and the audit partner

   f) instructing the Corporation's external auditors that they are ultimately accountable to the Committee and the Board and that the Committee and the Board are responsible for the selection (subject to Shareholder approval), evaluation and termination of the Corporation's external auditors

   g) have a private meeting with the external auditors at every quarterly Committee meeting

   h) obtain annually the auditors' views on competency and integrity of the Committee and senior financial executives

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

5. Review and approve the annual audit plan of the external auditors, including the scope of audit activities, and monitor such plan's progress and results quarterly and at year end

6. Confirm, through private discussions with the external auditors and management, that no restrictions are being placed on the scope of the external auditors' work

7. Review the appropriateness of management's representation letter transmitted to the external auditors

8. Receipt of certifications from the CEO and CFO

9. Review with management the adequacy of annual and quarterly financial statements and disclosure in the management discussion and analysis and press release and recommend approval to the Board of:

   a) satisfactory answers from management following the review of the annual and quarterly financial statements and management discussion and analysis and press release

b) the qualitative judgments of the external auditors about the appropriateness, not just the acceptability, of accounting principles and financial disclosure practices used or proposed to be adopted by the Corporation and, particularly, their views about alternate accounting treatments and their effects on the financial results

c) the methods used to account for significant unusual transactions

d) the effect of significant accounting policies in controversial or emerging areas for which there is a lack of authoritative guidance or consensus

e) management's process for formulating sensitive accounting estimates and the reasonableness of these estimates

f) significant recorded and unrecorded audit adjustments

g) any material accounting issues among management and the external auditors

h) other matters required to be communicated to the Committee by the external auditors under generally accepted auditing standards and

i) management's acknowledgement of its responsibility towards the financial statements

j) significant legal, compliance or regulatory matters that may have a material effect on the financial statements or the business of the organization (including material notices to, or inquiries received from, governmental agencies) and

k) receive the report from the Reserves Committee over the appropriateness of reported reserves and resources

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

10. Establishment of the Corporation's Whistleblower Policy for the submission, receipt, retention and treatment of complaints and concerns regarding accounting and auditing matters, and review any developments and responses on reports received thereunder

11. Review the adequacy and effectiveness of the financial reporting system and internal control policies and procedures with the external auditors and management. Ensure that the Corporation complies with all new regulations in this regard

12. Review with management the Corporation's internal controls, and evaluate whether the Corporation is operating in accordance with prescribed policies and procedures

13. Review with management and the external auditors any reportable condition and material weaknesses affecting internal controls

14. Review the management disclosure and oversight Committee's CEO and CFO certification processes to ensure compliance with US 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 and

16. Review annually the report of the external auditors 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 key risk assessment and review the policies to monitor, mitigate and report such business risks and ESG 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 Information Form, 40-F and the Information Circular regarding the 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, review the adequacy of its Charter and bring 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

24. Hold an in-camera session of the independent members of the Committee at each meeting of the Committee

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

Enerplus Corporation

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