UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 40-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2016 Commission File Number 001-15150

ENERPLUS CORPORATION
(Exact name of Registrant as specified in its charter)

Alberta, Canada
(Province or other jurisdiction of incorporation or organization)

1311
(Primary Standard Industrial Classification Code Number (if applicable))

N/A
(I.R.S. Employer Identification Number (if applicable))

The Dome Tower, 3000, 333 - 7th Avenue S.W.
Calgary, Alberta, Canada T2P 2Z1
(403) 298-2200
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 Eighth Avenue, 13th Floor
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares	Toronto Stock Exchange
	The New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this Form:

☒ Annual information form ☒ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

240,482,928 Common Shares

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☒ No ☐

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 40-F contains or incorporates by reference forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Registrant. Undue reliance should not be placed on these forward-looking statements which are based upon management's assumptions and are subject to known and unknown risks and uncertainties which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. For a description of some of these risks, uncertainties, events and circumstances, readers should review the disclosure under the heading "Risk Factors" in the Registrant's Annual Information Form for the year ended December 31, 2016, which is attached as Exhibit 99.1 to this Annual Report on Form 40-F, and under the heading "Risk Factors and Risk Management" in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2016, which is attached as Exhibit 99.3 to this Annual Report on Form 40-F, and is incorporated by reference herein. Other than as required by applicable law, the Registrant undertakes no obligation to update publicly or revise any forward-looking statements contained herein and such statements are expressly qualified by the cautionary statement.

ANNUAL INFORMATION FORM, AUDITED ANNUAL CONSOLIDATED FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION AND ANALYSIS

A. Annual Information Form

The Registrant's Annual Information Form for the year ended December 31, 2016 is attached as Exhibit 99.1 to this Annual Report on Form 40-F and is incorporated by reference herein.

B. Audited Annual Consolidated Financial Statements

The Registrant's audited annual consolidated financial statements for the year ended December 31, 2016, including the report of the independent registered public accounting firm with respect thereto, are attached as Exhibit 99.2 to this Annual Report on Form 40-F and are incorporated by reference herein.

C. Management's Discussion and Analysis

The Registrant's Management's Discussion and Analysis for the year ended December 31, 2016 is attached as Exhibit 99.3 to this Annual Report on Form 40-F and is incorporated by reference herein.

DISCLOSURE REGARDING CONTROLS AND PROCEDURES

A. Disclosure Controls and Procedures

As of the end of the Registrant's fiscal year ended December 31, 2016, an evaluation of the effectiveness of the Registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the Registrant's principal executive officer and principal financial officer. Based upon that evaluation, the Registrant's principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the Registrant's disclosure controls and procedures (which include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrant in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Registrant's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow for timely decisions regarding required disclosure) are effective to ensure that the information required to be disclosed by the Registrant in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

B. Management's Annual Report on Internal Control Over Financial Reporting

The Registrant's report of management on the Registrant's internal control over financial reporting is included under the heading "Management's Report on Internal Control Over Financial Reporting" contained in Exhibit 99.2 to this Annual Report on Form 40-F, which report of management is incorporated by reference herein.

C. Attestation Report of the Independent Registered Public Accounting Firm

The attestation report of the independent registered public accounting firm on the effectiveness of internal control over financial reporting is included under the heading "Report of Independent Registered Public Accounting Firm" contained in Exhibit 99.2 to this Annual Report on Form 40-F, which attestation report is incorporated by reference herein.

D. Changes in Internal Control over Financing Reporting

During the fiscal year ended December 31, 2016, there were no changes in the Registrant's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

None.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the Registrant has determined that Mr. Robert B. Hodgins, a member and the chairman of the Registrant's Audit & Risk Management Committee, is an "audit committee financial expert" (as such term is defined by the rules and regulations of the Securities and Exchange Commission) and is "independent" (as that term is defined by the New York Stock Exchange's listing standards applicable to the Registrant).

The Securities and Exchange Commission has indicated that the designation or identification of a person as an "audit committee financial expert" does not (i) mean that such person is an "expert" for any purpose, including without limitation for purposes of Section 11 of the Securities Act of 1933, (ii) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the audit committee and the board of directors in the absence of such designation or identification, or (iii) affect the duties, obligations or liability of any other member of the audit committee or the board of directors.

CODE OF ETHICS

The Registrant has adopted a "code of ethics" (as that term is defined by the rules and regulations of the Securities and Exchange Commission), entitled the "Code of Business Conduct" (as amended to the date of this Annual Report on Form 40-F, the "Code of Business Conduct"), that applies to each director, officer (including its principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions), employee and consultant of the Registrant. The Registrant has amended the Code of Business Conduct effective January 17, 2017. There were no amendments made to the Code of Business Conduct of a substantive nature. During the fiscal year ended December 31, 2016, there were no waivers, including implicit waivers, granted from any provision of the Code of Business Conduct that applied to the Registrant's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions.

The Code of Business Conduct is attached as Exhibit 99.11 to this Annual Report on Form 40-F and is incorporated by reference herein.

PRINCIPAL ACCOUNTANT FEES AND SERVICES AND PRE-APPROVAL POLICIES AND PROCEDURES

The aggregate fees paid by the Registrant to Deloitte LLP, Independent Registered Public Accountants, the Registrant's principal accountant, for professional services rendered in the Registrant's last two fiscal years are as follows:

	2016	2015
	(in Cdn$ thousands)	
Audit fees[(1)]	654.7	773.3
Audit-related fees[(2)]	—	—
Tax fees[(3)]	43.9	129.2
All other fees[(4)]	—	—
Total	698.6	902.6

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

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

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

(4) All other fees are fees for products and services provided by Deloitte LLP other than those described as "Audit fees", "Audit-related fees" and "Tax fees".

The Registrant's Audit & Risk Management Committee has implemented a policy restricting the services that may be provided by the Registrant's auditors and the fees paid to the Registrant's auditors. Prior to the engagement of the Registrant's auditors to perform both audit and non-audit services, the Audit & Risk Management Committee pre-approves the provision of the services. In making their determination regarding non-audit services, the Audit & Risk Management Committee considers the compliance with the policy and the provision of non-audit services in the context of avoiding an adverse impact on auditor independence. All audit and non-audit fees paid to Deloitte LLP in 2015 and 2016 were pre-approved by the Registrant's Audit & Risk Management Committee and none were approved on the basis of the de minimis exemption set forth in Rule 2-01(c)(7)(i)(C) of Regulation S-X. Based on the Audit & Risk Management Committee's discussions with management and the independent auditors, the committee is of the view that the provision of the non-audit services by Deloitte LLP described above is compatible with maintaining that firm's independence from the Registrant.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Registrant's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The following table sets forth the Registrant's known contractual obligations as of December 31, 2016:

	Payments due by period (in Cdn$ thousands)				
Contractual Obligations	**Total**	**2017**	**2018 to 2019**	**2020 to 2021**	**2022 +**
Bank credit facility[2]	$ 23,226	$ —	$ 23,226	$ —	$ —
Senior unsecured notes[2]	745,599	29,539	89,078	219,128	407,854
Transportation commitments	293,624	31,891	53,722	42,323	165,688
Processing commitments	42,931	11,427	20,272	3,100	8,132
Drilling and completions commitment	29,137	29,137	—	—	—
Office lease commitments	88,345	12,197	22,500	21,664	31,984
Sublease recoveries	(9,293)	(1,956)	(3,322)	(3,275)	(740)
Net office lease commitments	79,052	10,241	19,178	18,389	31,244
Total commitments[1][3]	$1,213,569	$112,235	$ 205,476	$ 282,940	$612,918

Notes:

(1) U.S. dollar commitments have been converted to Canadian dollars using the December 31, 2016 foreign exchange rate of US$1.00 = Cdn$1.34.

(2) Interest payments have not been included.

(3) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

Additional disclosure regarding the Registrant's contractual obligations as of December 31, 2016 is provided under the heading "Liquidity and Capital Resources — Commitments" in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2016 attached as Exhibit 99.3 to this Annual Report on Form 40-F, which disclosure is incorporated by reference herein, and in Note 16 to the Registrant's audited annual consolidated financial statements for the year ended December 31, 2016 attached as Exhibit 99.2 to this Annual Report on Form 40-F, which note is incorporated by reference herein.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the Registrant's Audit & Risk Management Committee are Robert B. Hodgins (as Chairman), Michael R. Culbert, Hilary A. Foulkes, Glen D. Roane and Sheldon B. Steeves. Elliott Pew, the chairman of the board of directors of the Registrant, is an *ex officio* member of the Audit & Risk Management Committee.

COMPLIANCE WITH NYSE CORPORATE GOVERNANCE RULES

The Registrant has reviewed the New York Stock Exchange's corporate governance rules and confirms that the Registrant's corporate governance practices are not significantly nor materially different than those required of domestic companies under the New York Stock Exchange's listing standards.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

1. The Registrant previously filed with the Commission a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

2. Any change to the name or address of the Registrant's agent for service shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of the Registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

ENERPLUS CORPORATION

By: /s/ IAN C. DUNDAS
Ian C. Dundas
President and Chief Executive Officer

Date: February 24, 2017

EXHIBIT INDEX

99.1	Annual Information Form for the year ended December 31, 2016 dated February 24, 2017.
99.2	Audited annual consolidated financial statements for the year ended December 31, 2016.
99.3	Management's Discussion and Analysis for the year ended December 31, 2016.
99.4	Consent of Independent Registered Public Accounting Firm.
99.5	Consent of McDaniel & Associates Consultants Ltd.
99.6	Consent of Netherland, Sewell & Associates, Inc.
99.7	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934.
99.8	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934.
99.9	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.10	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.11	Code of Business Conduct.
99.12	Supplemental Information About Oil and Gas Producing Activities.
101	Interactive Data File.

Exhibit 99.1

ANNUAL INFORMATION FORM

For the year ended December 31, 2016

February 24, 2017

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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 24, 2017 for the year ended December 31, 2016 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, 2016, 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;

"**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;

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

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

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

"**McDaniel Reports**" means, collectively, the independent engineering evaluations of the Corporation's oil, natural gas liquids and natural gas reserves in Canada and the Corporation's oil, natural gas liquids and natural gas reserves in the United States prepared by McDaniel effective December 31, 2016, utilizing commodity price forecasts of McDaniel as of January 1, 2017;

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

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

"**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, 2016, utilizing commodity price forecasts of McDaniel (for internal consistency in the Corporation's reserves reporting) as of January 1, 2017;

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

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

"**Senior Unsecured Notes**" means, as at December 31, 2016, the US$533 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*";

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

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

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

Abbreviations and Conversions

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

API	American Petroleum Institute 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	billion cubic feet
BcfGE(1)	one billion cubic feet of natural gas equivalent
BOE(1)	barrels of oil equivalent
BOE/day	barrels of oil equivalent per day
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
NGLs	natural gas liquids
NPV	net present value of future net revenue, discounted at 10%
NYMEX	the New York Mercantile Exchange
Tcf	trillion cubic feet
WTI	West Texas Intermediate crude oil that serves as the benchmark crude oil for the NYMEX crude oil contract delivered in Cushing, Oklahoma

Note: (1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to BcfGEs. For further information, see "*Presentation of Oil and Gas Reserves, 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 30, 2016, the exchange rate for one U.S. dollar, expressed in Canadian dollars and based upon the noon buying rate of the Bank of Canada, was CDN$1.3427.

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, 2016 and the preparation dates for such information are January 25, 2017 for the McDaniel Reports and February 3, 2017 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 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. Moreover, in accordance with Canadian disclosure requirements, the Corporation has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC generally requires that reserves estimates be prepared using an unweighted average of the closing prices for the applicable commodity on the first day of each of the twelve months preceding the company's fiscal year-end, with the option of also disclosing reserves estimates based upon future or other prices. As a consequence of the foregoing, the Corporation's reserves estimates and production volumes may not be comparable to those made by companies utilizing United States reporting and disclosure standards. Additionally, the SEC prohibits disclosure of oil and gas resources in SEC filings, including contingent resources, whereas Canadian 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 and BcfGEs. BOEs, MBOEs, MMBOEs, and BcfGEs may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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; and

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

"**net**" means:

(i) in relation to the Corporation's interest in production, 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; and

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

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

RESERVES CATEGORIES AND LEVELS OF CERTAINTY FOR REPORTED RESERVES

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

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

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

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

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

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

DEVELOPMENT AND PRODUCTION STATUS

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

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

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

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

DESCRIPTION OF PRICE AND COST ASSUMPTIONS

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

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

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

Presentation of Financial Information

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

The Corporation continues to qualify as a foreign private issuer for its U.S. securities filings as less than 50% of the book value of its assets is in the United States, as calculated under U.S. GAAP as at June 30, 2016. The Corporation is required to reassess this annually, at the end of the second quarter. See "*Risk Factors – Government regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs*".

Forward-Looking Statements and Information

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

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

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

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

The Corporation's current 2017 capital expenditure budget contained in this Annual Information Form assumes: WTI price of US$55.00/bbl; NYMEX gas price of US$3.00/Mcf; AECO gas price of $2.75/GJ; and a foreign exchange rate of USD/CDN 1.35.

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

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

- volatility, including further decline, in market prices for oil, NGLs and natural gas, including changes in supply or demand for those products;
- actions, by governmental or regulatory authorities, including different interpretations of applicable laws, treaties or administrative positions, as well as changes in income tax laws or changes in royalty regimes and incentive programs relating to the oil and gas industry;
- unanticipated operating results, including changes or fluctuations in oil, NGLs and natural gas production levels;
- changes in foreign currency exchange rates, 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 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;
- the Corporation's success at the acquisition, exploitation and development of reserves and resources;
- changes in general economic, market (including credit market) and business conditions in Canada, North America and worldwide; and
- changes in tax, environmental, regulatory, or other legislation applicable to the Corporation and its operations, and the Corporation's ability to comply with current and future environmental legislation and regulations and other laws and regulations, 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 for the year ended December 31, 2016, which is available on the internet on the Corporation's SEDAR profile at www.sedar.com, on the Corporation's EDGAR profile at www.sec.gov as part of the annual report on Form 40-F filed with the SEC together with this Annual Information Form, and on the Corporation's website at www.enerplus.com. Readers are also referred to the risk factors described in this Annual Information Form under "*Risk Factors*" and in other documents the Corporation files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the Corporation or electronically on the internet on the Corporation's

SEDAR profile at www.sedar.com, on the Corporation's EDGAR profile at www.sec.gov and on the Corporation's website at www.enerplus.com.

Corporate Structure

ENERPLUS CORPORATION

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

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

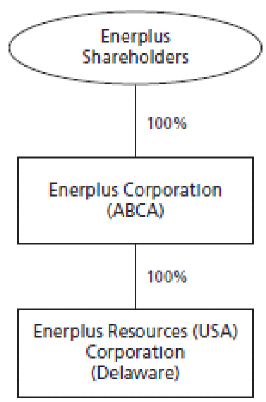
The head, principal and registered office of the Corporation is located at The Dome Tower, 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1. The Corporation also has a U.S. office located at 950 - 17th Street, Suite 2200, Denver, Colorado, 80202-2805. The Common Shares are currently traded on the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

MATERIAL SUBSIDIARIES

As of December 31, 2016, 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, 2016 is set forth below.



General Development of the Business

DEVELOPMENTS IN THE PAST THREE YEARS

Developments in 2014

FINANCING

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

SALE OF ASSETS

In 2014, the Corporation realized proceeds of over $200 million from divestment activities involving certain of the Corporation's Deep Basin assets in Canada and its gross overriding royalty interest in the Jonah natural gas property in the United States. These divestments included in aggregate approximately 3,500 BOE/day of production. The proceeds from the Corporation's divestment activities were used to fund the Corporation's capital program and to reduce indebtedness under the Bank Credit Facility.

SUCCESSION OF CHAIRMAN OF THE BOARD OF DIRECTORS

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

Developments in 2015

SALE OF ASSETS

In 2015, the Corporation realized proceeds of approximately $286.6 million from divestment activities involving certain of the Corporation's assets. These divestments included approximately 6,200 BOE/day of production, in aggregate, from non-core shallow gas assets and Pembina waterflood assets in Canada, as well as certain non-operated North Dakota assets and operated Marcellus assets in the United States. The proceeds from the Corporation's divestment activities were used to fund the Corporation's capital program as well as the principal instalments due on its Senior Unsecured Notes.

SUCCESSION OF SENIOR VICE PRESIDENT & CHIEF FINANCIAL OFFICER

Ms. Jodine J. Jenson Labrie succeeded Mr. Robert J. Waters as the Senior Vice President & Chief Financial Officer effective September 15, 2015. Prior thereto, Ms. Jenson Labrie held the position of Vice President, Finance of the Corporation. See "*Directors and Officers*".

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.

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, and Pennsylvania, as well as in western Canada in the provinces of Alberta, British Columbia and Saskatchewan. Capital spending on these assets in 2016 totaled approximately $209 million with over 85% of this focused on the Corporation’s crude oil assets in North Dakota and waterflood projects in Canada.

In the United States, capital spending on the Bakken and Three Forks assets in North Dakota totaled $136 million during 2016. In Canada, capital spending of approximately $44 million in 2016 was directed to crude oil waterflood projects at Cadogan, Giltedge, Medicine Hat and southeast Saskatchewan. Capital spending on the Corporation’s natural gas interests in northeast Pennsylvania was approximately $24 million, about 25% less than in 2015, due to low regional natural gas prices. Canadian natural gas assets received a minimal amount of maintenance capital during 2016; the Corporation’s focus was on retaining value and reducing operating costs for these assets.

During 2016, the Corporation continued to concentrate its portfolio, divesting of certain crude oil and natural gas assets in Canada and the United States for total proceeds of approximately $670 million, after closing adjustments. These assets had associated production of approximately 13,500 BOE/day (60% natural gas). In November 2016, the Corporation acquired a waterflood asset in Northern Alberta’s Ante Creek area, with associated average production of 3,800 BOE/day, for approximately $110 million, after closing adjustments.

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, 2016 from the Corporation's properties consisted of approximately 46% crude oil and NGLs and 54% natural gas, on a BOE basis. The Corporation's 2016 average daily production was 93,125 BOE/day, comprised of 38,353 bbls/day of crude oil, 4,903 bbls/day of NGLs and 299,214 Mcf/day of natural gas, a decrease of approximately 13% compared to 2015 average daily production of 106,524 BOE/day, comprised of 41,639 bbls/day of crude oil, 4,763 bbls/day of NGLs and 360,733 Mcf/day of natural gas. The decrease in average daily production during 2016 is largely attributable to a reduction in capital spending during 2016, combined with the divestment of non-strategic crude oil and natural gas assets mentioned previously. The Corporation’s 2016 production in the United States was approximately 71% of its total production, with the remaining 29% from Canada. Approximately 53% of the Corporation’s 2016 production was operated by the Corporation, with the remainder operated by industry partners.

As at December 31, 2016, the oil and natural gas property interests held by the Corporation were estimated to contain proved plus probable gross reserves of approximately 14.3 MMbbls of light and medium crude oil, 39.0 MMbbls of heavy crude oil, 123.0 MMbbls of tight oil, 18.1 MMbbls of NGLs, 126.3 Bcf of conventional natural gas and 1,002.8 Bcf of shale gas, for a total of 382.5 MMBOE. The Corporation's proved reserves represented approximately 70% of total proved plus probable reserves, with approximately 51% 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, 2016, (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, 2016, on a BOE basis, approximately 71% of the Corporation's production was derived from the United States (31% from North Dakota, 35% from Pennsylvania and 5% from Montana) and approximately

29% from Canada (21% from Alberta, 6% from Saskatchewan and 2% 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, 2016.

2016 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							
Marcellus, Pennsylvania	-	-	-	-	-	195,317	32,553
Fort Berthold, North Dakota(1)	-	-	22,114	3,490	-	17,798	28,570
Sleeping Giant, Montana	-	-	3,150	5	-	7,042	4,329
Total United States	-	-	25,264	3,495	-	220,157	65,452
Canada							
Medicine Hat Glauconitic "C" East Unit, Alberta	-	3,423	-	-	322	-	3,476
Brooks, Alberta	-	2,155	-	39	6,389	-	3,259
Freda Lake, Saskatchewan	3,002	-	-	-	-	-	3,002
Tommy Lakes, British Columbia	70	-	-	196	10,789	-	2,064
Shackleton, Saskatchewan	-	-	-	-	12,357	-	2,060
Giltedge, Alberta	-	1,594	-	-	58	-	1,604
Willesden North, Alberta	3	-	-	229	3,633	-	837
Hanna Garden, Alberta	-	-	-	-	4,595	-	766
Cadogan, Alberta	-	722	-	10	191	-	764
Pine Creek, Alberta	2	-	-	144	3,508	-	731
Medicine Hat, Alberta	-	-	-	-	4,124	-	687
Joarcam, Alberta	367	-	-	23	1,231	-	595
Kaybob South, Alberta	1	-	-	167	1,874	-	480
Ante Creek, Alberta(2)	194	-	-	10	1,165	-	398
Other Canada(3)	1,173	383	-	590	28,074	747	6,950
Total Canada	4,812	8,277	-	1,408	78,310	747	27,673
Total	4,812	8,277	25,264	4,903	78,310	220,904	93,125

Notes:

(1) North Dakota non-operated assets were sold on December 30, 2016. These assets had associated production of approximately 5,000 BOE/day, which is included in the table above.

(2) Acquired on November 15, 2016.

(3) A portion was sold during 2016, the largest of which included the Wilrich asset, as well as Pouce Coupe, Progress and Valhalla properties in the Peace River Arch area. Total production associated with these divestments was approximated at 8,500 BOE/day, which is not included in the table above.

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

CAPITAL EXPENDITURES AND COSTS INCURRED

The Corporation invested approximately $209 million in its capital program during 2016, approximately 92% of which was directed to oil-related projects, compared to total capital spending in 2015 of approximately $493 million. Capital investment during 2016 was focused on the Corporation’s U.S. North Dakota Bakken crude oil property, where it invested $136 million, its U.S. Marcellus assets with investment of $24 million, as well as in its Canadian waterflood properties where it invested $44 million.

In the financial year ended December 31, 2016, the Corporation made the following expenditures in the categories noted, as prescribed by NI 51-101:

	Property Acquisition Costs		**Exploration Costs**	**Development Costs**
	Proved	**Unproved**		
	($ in millions)			
Canada	$ 49.0	$ 65.4	$ 0.7	$ 43.7
United States	1.8	9.9	2.2	162.5
Total	$ 50.8	$ 75.3	$ 2.9	$ 206.2

Based on the commodity price environment as of the date hereof, the Corporation currently expects its 2017 exploration and development capital spending to be approximately $450 million, with approximately 87% of this spending projected to be invested in the Corporation's U.S. and Canadian crude oil projects. The Corporation currently expects to invest approximately 74% of its planned 2017 capital spending on its Fort Berthold property in the United States and 13% on its Canadian oil assets. In addition, the Corporation intends to spend approximately 13% of its 2017 capital on its Marcellus properties in the northeast region of Pennsylvania.

The Corporation intends to finance its 2017 capital expenditure program through a combination of internally generated cash flow and debt. The Corporation will review its 2017 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 2016 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, 2016, in each of Canada and the United States. Wells have been classified in accordance with the definitions of such terms in NI 51-101.

	Canada				**United States**			
	Development Wells		**Exploratory Wells**		**Development Wells**		**Exploratory Wells**	
Category of Well	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude oil wells	7	5	-	-	25	16	-	-
Natural gas wells	-	-	-	-	14	1	-	-
Service wells	4	4	-	-	-	-	-	-
Dry and abandoned wells	-	-	-	-	-	-	-	-
Total	11	9	-	-	39	17	-	-

For a description of the Corporation's 2017 development plans and the anticipated sources of funding these plans, see "*Capital Expenditures and Costs Incurred*", above.

OIL AND NATURAL GAS WELLS AND UNPROVED PROPERTIES

The following table summarizes, as at December 31, 2016, the Corporation's interests in producing wells and in non-producing wells which were not producing but which may be capable of production, along with the Corporation's interests in unproved properties (as defined in NI 51-101). Although many wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the proportion of oil or natural gas production that constitutes the majority of production from that well.

	Producing Wells				Non-Producing Wells				Unproved Properties (acres)	
	Oil		Natural Gas		Oil		Natural Gas			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Alberta	943	532	2,689	1,372	536	251	507	182	304,600	200,100
Saskatchewan	751	110	1,521	1,460	283	43	750	713	119,200	107,500
British Columbia	-	-	160	147	-	-	17	11	38,200	30,900
United States										
Colorado	-	-	-	-	-	-	-	-	27,728	27,728
Montana	243	164	-	-	20	18	-	-	-	-
North Dakota	155	128	-	-	15	12	-	-	-	-
Pennsylvania	-	-	732	80	-	-	90	8	82,119	23,141
Total	2,092	934	5,102	3,059	854	325	1,364	913	571,847	389,369

The Corporation expects its rights to explore, develop and exploit on approximately 21,200 net acres of unproved properties in Canada and the United States to expire, in the ordinary course, prior to December 31, 2017. The Corporation has no material work commitments on such properties and, where the Corporation determines appropriate, it can extend expiring leases by either making the necessary applications to extend or performing the necessary work.

DESCRIPTION OF PROPERTIES

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

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 and in Richland County, Montana. The Corporation has approximately 65,500 net acres of land in Fort Berthold, primarily in Dunn and McKenzie counties and, on a production basis, operated approximately 81% of its Fort Berthold asset (prior to the divestment of its non-operated assets described below). 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 approximately 28,570 BOE/day in 2016.

During the fourth quarter of 2016, the Corporation announced the sale of non-operated North Dakota Bakken assets having associated production of approximately 5,000 BOE/day and proved plus probable reserves of 12.0 MMBOE. On December 30, 2016, the Corporation closed this sale for proceeds of approximately $392 million, after closing adjustments.

Approximately 17.5 MMBOE of proved plus probable reserves were added at Fort Berthold during 2016, including due to technical revisions; however, after adjusting for the non-operated divestments of 12.0 MMBOE and 2016 production of 10.4 MMBOE, total proved plus probable reserves associated with this property as at December 31, 2016 were 138.7 MMBOE, 3% lower than as at December 31, 2015.

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 4,329 BOE/day on average from the Bakken formation in 2016. The Corporation believes there is additional upside potential at the Sleeping Giant property through production optimization, refracs, limited infill drilling and the potential for Enhanced Oil Recovery ("**EOR**") techniques.

Overall, the Corporation's U.S. Williston Basin crude oil properties produced an average of approximately 32,900 BOE/day in 2016. On a BOE basis, this represents 76% of the Corporation's crude oil and NGLs production, and 35% of the Corporation's 2016 average daily production.

The Corporation spent approximately $140 million on its U.S. crude oil assets in 2016, with approximately $136 million of that spending directed to its operated assets in North Dakota where the Corporation continued to advance its completions techniques. During 2016, the Corporation drilled approximately 16 net horizontal wells in the Fort Berthold region, targeting both the Bakken and Three Forks formations (consisting of 4.0 short lateral wells and 12.0 long lateral wells) with approximately 16.1 net wells brought on-stream.

The Corporation had 156.0 MMBOE of proved plus probable reserves associated with its U.S. crude oil assets at December 31, 2016, representing approximately 41% of its total proved plus probable reserves.

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 approximately 39,100 net acres. The Corporation's Marcellus shale gas production averaged 195,317 Mcf/day in 2016, representing approximately 65% of the Corporation's total natural gas production. While 2016 regional demand growth and the addition of incremental interstate pipeline capacity helped reduce infrastructure constraints, for both the Corporation and other producers in northeast Pennsylvania, the Corporation's production was curtailed at times due to low regional spot pricing. See "*Risk Factors – Lack of adequately developed infrastructure may result in a decline in the Corporation's ability to market oil and natural gas production*".

In 2016, approximately $24 million was invested in the Corporation's interests in the Marcellus. The Corporation participated in the drilling of a total of approximately 1.4 net wells, and a total of approximately 5.2 net wells were brought on-stream. The Corporation currently has 80.0 net producing wells in the Marcellus, and 4.2 net wells waiting on completion or tie-in.

Proved plus probable Marcellus shale gas reserves were 894.6 Bcf as at December 31, 2016, an increase of 53.6 Bcf from 2015, and represented approximately 39% of the Corporation's 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 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.

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. In traditional waterflooding, water is injected into the formation through 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 production profile with more predictable and stable declines and 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 waterflood assets provide a stable production base with free cash flow to support the Corporation’s investment in growth plays, as well as its dividend. Canadian crude oil properties production averaged 16,160 BOE/day during 2016, or 33% of the Corporation’s crude oil properties production during the year. The Canadian crude oil properties where the Corporation invested its capital in 2016 included Mannville oil production in Medicine Hat and Cadogan in Alberta, as well as southeast Saskatchewan, which produces from the Mississippian Ratcliffe formation. On a production basis, the Corporation operated over 89% of its Canadian crude oil properties.

In 2016, the Corporation invested approximately $44 million in its Canadian crude oil properties, with approximately 50% directed to drilling and completions and the remainder on plant and facility enhancements to support future activities. The Corporation drilled 8.0 net crude oil wells (inclusive of water injection wells) in its Canadian waterflood assets in 2016, advancing projects targeting the Mannville and Ratcliffe plays. At Medicine Hat, polymer injection continued on the Corporation’s second polymer pilot with results in line with expectations.

In November 2016, the Corporation acquired a waterflood property in Northern Alberta’s Ante Creek area with associated average production of 3,800 BOE/day, for approximately $110 million, net of closing adjustments. At December 31, 2016, proved plus probable reserves associated with this property were 4.8 MMBOE.

Of the 59.9 MMBOE of proved plus probable reserves associated with the Corporation’s Canadian crude oil properties at December 31, 2016, 59.5 MMBOE (or approximately 16% of the Corporation’s total proved plus probable reserves) were associated with the Canadian crude oil waterflood properties, including those acquired at Ante Creek.

Canadian Natural Gas Properties

OVERVIEW

The Corporation's Canadian natural gas properties are located in Alberta, Saskatchewan and British Columbia. During 2016, the Corporation focused on divesting non-strategic assets within its Canadian natural gas portfolio.

Production from the Corporation's Canadian natural gas properties averaged 69,144 Mcf/day in 2016. The Corporation's largest producing Canadian natural gas properties in 2016 were Shackleton, Tommy Lakes and Brooks.

The Corporation spent a minimal amount of capital on its Canadian natural gas assets during 2016, where the focus was on maintenance and optimization of operations. The Corporation spent approximately $7 million on abandonment and reclamation activities on these assets in 2016.

Canadian natural gas properties proved plus probable reserves totaled 105 BcfGE as at December 31, 2016. Canadian natural gas proved plus probable reserves represent approximately 5% of the Corporation's total proved plus probable reserves, measured on a BOE basis, at December 31, 2016.

During 2016, the Corporation divested assets in the Alberta Deep Basin (Ansell area) in two separate transactions for aggregate consideration of approximately $186 million, net of closing adjustments. Production associated with these assets was 5,400 BOE/day (97% natural gas). In addition to the divestment of its Deep Basin assets, the Corporation divested of some high operating cost shallow gas assets in southeast Alberta, as well as its Pouce Coupe, Progress and Valhalla assets in the Peace River Arch area of Alberta. Combined, these assets were expected to produce approximately 3,100 BOE/day. The Corporation received total proceeds of approximately $94 million in respect of these two divestments, net of closing adjustments.

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 2016 and for the entire year, separately for production in Canada and the United States, and in total.

	Year Ended December 31, 2016				
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)	25,322	25,582	25,444	24,711	**25,264**
Total crude oil (bbls/day)	25,322	25,582	25,444	24,711	**25,264**
Natural gas liquids (bbls/day)	3,690	3,411	3,627	3,253	**3,495**
Total liquids (bbls/day)	29,012	28,993	29,071	27,964	**28,759**
Conventional natural gas (Mcf/day)	-	-	-	-	**-**
Shale gas (Mcf/day)	217,611	218,625	228,271	216,078	**220,157**
Total United States (BOE/day)	**65,280**	**65,431**	**67,116**	**63,977**	**65,452**
Canada					
Light and medium oil (bbls/day)	5,607	5,044	3,970	4,640	**4,812**
Heavy oil (bbls/day)	8,579	8,453	8,303	7,777	**8,277**
Tight oil (bbls/day)	-	-	-	-	**-**
Total crude oil (bbls/day)	14,186	13,497	12,273	12,417	**13,089**
Natural gas liquids (bbls/day)	1,804	1,418	1,254	1,160	**1,408**
Total liquids (bbls/day)	15,990	14,915	13,527	13,577	**14,497**
Conventional natural gas (Mcf/day)	98,610	78,950	68,048	67,861	**78,310**
Shale gas (Mcf/day)	929	928	557	576	**747**
Total Canada (BOE/day)	**32,580**	**28,228**	**24,961**	**24,983**	**27,673**
Total					
Light and medium oil (bbls/day)	5,607	5,044	3,970	4,640	**4,812**
Heavy oil (bbls/day)	8,579	8,453	8,303	7,777	**8,277**
Tight oil (bbls/day)	25,322	25,582	25,444	24,711	**25,264**
Total crude oil (bbls/day)	39,508	39,079	37,717	37,128	**38,353**
Natural gas liquids (bbls/day)	5,494	4,829	4,881	4,413	**4,903**
Total liquids (bbls/day)	45,002	43,908	42,598	41,541	**43,256**
Conventional natural gas (Mcf/day)	98,610	78,950	68,048	67,861	**78,310**
Shale gas (Mcf/day)	218,540	219,553	228,828	216,654	**220,904**
Total (BOE/day)	**97,860**	**93,659**	**92,077**	**88,960**	**93,125**

QUARTERLY NETBACK HISTORY

The following tables set forth the Corporation's average netbacks received for each fiscal quarter in 2016 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, 2016				
Light and Medium Crude Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price(1)	$ 30.14	$ 46.73	$ 47.50	$ 52.76	**$ 43.55**
Royalties(2)	(4.84)	(8.14)	(11.05)	(10.80)	**(8.44)**
Production costs(3)	(14.79)	(7.90)	(15.31)	(14.25)	**(12.97)**
Netback	$ 10.51	$ 30.69	$ 21.14	$ 27.71	**$ 22.14**

	Year Ended December 31, 2016				
Heavy Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price(1)	$ 22.88	$ 38.89	$ 38.77	$ 43.98	**$ 35.94**
Royalties(2)	(4.32)	(6.36)	(7.09)	(8.23)	**(6.47)**
Production costs(3)	(12.44)	(11.64)	(17.43)	(17.18)	**(14.61)**
Netback	$ 6.12	$ 20.89	$ 14.25	$ 18.57	**$ 14.86**

	Year Ended December 31, 2016				
Tight Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States					
Sales price(1)	$ 31.79	$ 45.51	$ 47.75	$ 54.15	**$ 44.78**
Royalties(2)	(9.17)	(12.55)	(13.31)	(16.43)	**(12.85)**
Production costs(3)	(12.02)	(12.66)	(10.74)	(11.94)	**(11.84)**
Netback	$ 10.60	$ 20.30	$ 23.70	$ 25.78	**$ 20.09**

Natural Gas Liquids ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price(1)	$ 24.21	$ 24.37	$ 24.98	$ 35.43	**$ 26.75**
Royalties(2)	(4.60)	(6.08)	(5.67)	(7.59)	**(5.83)**
Production costs(3)	-	-	-	-	**-**
Netback	$ 19.61	$ 18.29	$ 19.31	$ 27.84	**$ 20.92**
United States					
Sales price(1)	$ (0.33)	$ 6.81	$ 4.37	$ 11.04	**$ 5.29**
Royalties(2)	(0.35)	(1.69)	(1.45)	(2.75)	**(1.52)**
Production costs(3)	-	-	-	-	**-**
Netback	$ (0.68)	$ 5.12	$ 2.92	$ 8.29	**$ 3.77**

	Year Ended December 31, 2016				
Conventional Natural Gas ($ per Mcf)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price(1)	$ 1.74	$ 1.13	$ 2.19	$ 2.84	**$ 1.92**
Royalties(2)	0.04	(0.07)	(0.12)	(0.02)	**(0.03)**
Production costs(3)	(2.94)	(2.48)	(1.78)	(1.86)	**(2.34)**
Netback	$ (1.16)	$ (1.42)	$ 0.29	$ 0.96	**$ (0.45)**

Shale Gas ($ per Mcf)	Year Ended December 31, 2016 First Quarter		Second Quarter		Third Quarter		Fourth Quarter		Annual	
United States										
Sales price[1]	$	0.99	$	0.87	$	1.14	$	1.88	**$**	**1.22**
Royalties[2]		(0.39)		(0.36)		(0.44)		(0.58)		**(0.44)**
Production costs[3]		(0.06)		(0.03)		(0.05)		(0.07)		**(0.05)**
Netback	$	0.54	$	0.48	$	0.65	$	1.23	**$**	**0.73**
Canada	$	1.68	$	1.61	$	2.84	$	3.65	**$**	**2.26**
Royalties[2]		(0.11)		(0.07)		(0.13)		(0.16)		**(0.11)**
Production costs[3]		(1.38)		(1.34)		(1.69)		(2.52)		**(1.65)**
Netback	$	0.19	$	0.20	$	1.02	$	0.97	**$**	**0.50**

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

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 in 2017. These expectations may vary depending on numerous factors, including fluctuations in commodity prices, and the Corporation's capital spending, changes in governing tax laws, and the nature and timing of the Corporation's acquisitions and 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, including those affecting tax, royalties and other financial matters, and interpretations of those laws, may adversely affect the Corporation and its securityholders"*.

For additional information, see Notes 2(i) and 13 to the Corporation's audited consolidated financial statements for the year ended December 31, 2016 and the information under the heading "Taxes" in the Corporation's MD&A for the year ended December 31, 2016.

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, 30-day negotiated contracts for crude oil in the United States, and yearly contracts for NGLs in Canada, where terms fluctuate with the monthly spot markets. NGL contracts in the United States are processing arrangement-linked contracts 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 $44.84/bbl for its crude oil and $15.29/bbl for its NGLs for the year ended December 31, 2016, compared to $48.43/bbl for its crude oil and $18.06/bbl for its NGLs for the year ended December 31, 2015.

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 approximately 2,700 BOE/day of crude oil and NGLs firm take-or-pay pipeline transportation agreements in place for 2017, and then approximately 1,800 BOE/day on average for 2018 through 2027 for its Alberta crude oil and condensate production. Additionally, the Corporation had contracted firm NGLs fractionation agreements for 825 BOE/day at the end of 2016, and this increases to 1,125 BOE/day from April 2017 through 2026.

In the United States, the Corporation transports its U.S. crude oil production to its buyers by pipeline and/or truck, in addition to selling a portion of its crude oil production to buyers who may utilize rail transportation after title is transferred into the buyer's name. The Corporation has a mix of approximately 12,500 bbls/day of firm sales contracts on average during 2017 for its U.S. oil production. The Corporation's NGLs associated with its U.S. crude oil production volumes are marketed on its behalf by midstream companies in North Dakota and Montana.

Natural Gas

In marketing its natural gas production, the Corporation strives for a mix of contracts and customers. In Canada, the Corporation sells its natural gas production at a mix of fixed and floating prices for a variety of terms ranging from spot sales to one year or longer. The Corporation's monthly sales portfolio reflected a mix of the daily and monthly AECO market indices, as well as the basis differential to NYMEX gas prices in 2016. Approximately 26% of the Corporation's total natural gas production originated in Canada in 2016 and received an average price, before transportation, royalties, and the effects of commodity derivative instruments, of $2.20/Mcf during the year. As at December 31, 2016, the Corporation held firm service natural gas transportation contracts for its natural gas production in Canada for 2017 totalling 99 MMcf/day.

In 2016, approximately 74% of the Corporation's natural gas production originated in the United States. The Corporation delivered approximately 47% of its Marcellus production in 2016 onto the Transco Leidy Pipeline, with the majority of the remaining volumes delivered onto the Tennessee Gas Pipeline 300 Line, in Pennsylvania, a portion of which is 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 nine years with buyers holding pipeline capacity on these and other pipelines in the region. The Corporation also has firm transportation agreements for approximately 66 MMcf/day, with terms ending between 2020 and 2036. The Corporation also holds a contract for five years of firm transportation capacity for 30 MMcf/day on the PennEast pipeline project. This project has an expected in-service date of late 2018, depending on regulatory approvals.

The Corporation received an average price differential for its U.S. Marcellus shale gas production of US$0.93/Mcf below NYMEX prices. Approximately 11% of the Corporation's U.S. natural gas production was associated natural gas production from its crude oil operations in North Dakota and Montana. The Corporation does not market these volumes directly, as they are marketed on Enerplus' behalf by midstream companies.

The Corporation's percentage of 2016 revenues attributable to natural gas (before transportation and cash operating costs, royalties, and the effects of commodity derivative instruments) was 26%, a decrease of approximately 1% from 2015. The average price received by the Corporation (before transportation and cash operating costs, royalties, and the effects of commodity derivative instruments) for its natural gas in 2016 was $2.06/Mcf compared to $2.15/Mcf for the year ended December 31, 2015.

Future Commitments and Forward Contracts

The Corporation may use various types of derivative financial instruments and fixed price physical sales contracts to manage the risk related to fluctuating commodity prices. Absent such hedging activities, all of the crude oil and NGLs and the majority of natural gas production of the Corporation is sold into the open market at prevailing market prices, which exposes the Corporation to the risks associated with commodity price fluctuations and foreign exchange rates. See "*Risk Factors*". Information regarding the Corporation's financial instruments is contained in Note 15(b) and (c)(i) to the Corporation's audited consolidated financial statements for the year ended December 31, 2016 and under the heading "*Results of Operations – Price Risk Management*" in the Corporation's MD&A for the year ended December 31, 2016, 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 86% 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 48% 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 and Montana. The Corporation has evaluated the remaining 52% 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 McDaniel's January 1, 2017 forecast prices and inflation rates to prepare its report.

The Corporation used McDaniel's forecast exchange rates, set forth below, to convert U.S. dollar amounts in 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, 2016, 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, 2015 to December 31, 2016, 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, 2016, using forecast price and cost cases.

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

As of December 31, 2016

	OIL AND NATURAL GAS RESERVES													
	Light & Medium Oil		**Heavy Oil**		**Tight Oil**		**Natural Gas Liquids**		**Conventional Natural Gas**		**Shale Gas**		**Total**	
RESERVES 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	11,306	9,677	26,388	21,857	-	-	2,033	1,697	89,205	87,416	1,527	1,450	54,848	48,042
United States	-	-	-	-	45,402	36,740	6,209	4,978	-	-	507,688	407,023	136,225	109,555
Total	**11,306**	**9,677**	**26,388**	**21,857**	**45,402**	**36,740**	**8,242**	**6,675**	**89,205**	**87,416**	**509,215**	**408,473**	**191,073**	**157,597**
Proved Developed Non-Producing														
Canada	15	14	-	-	-	-	17	12	4,839	3,966	-	-	838	688
United States	-	-	-	-	420	351	-	-	-	-	989	827	585	489
Total	**15**	**14**	**-**	**-**	**420**	**351**	**17**	**12**	**4,839**	**3,966**	**989**	**827**	**1,423**	**1,177**
Proved Undeveloped														
Canada	300	277	3,845	3,119	-	-	11	7	1,726	1,336	-	-	4,443	3,626
United States	-	-	-	-	31,744	25,300	3,555	2,834	-	-	216,411	173,076	71,368	56,980
Total	**300**	**277**	**3,845**	**3,119**	**31,744**	**25,300**	**3,566**	**2,841**	**1,726**	**1,336**	**216,411**	**173,076**	**75,811**	**60,606**
Total Proved														
Canada	11,621	9,968	30,232	24,976	-	-	2,061	1,716	95,769	92,717	1,527	1,450	60,130	52,355
United States	-	-	-	-	77,566	62,391	9,764	7,812	-	-	725,087	580,925	208,178	167,024
Total	**11,621**	**9,968**	**30,232**	**24,976**	**77,566**	**62,391**	**11,825**	**9,528**	**95,769**	**92,717**	**726,614**	**582,375**	**268,308**	**219,379**
Probable														
Canada	2,645	2,246	8,721	7,057	-	-	704	586	30,521	29,140	619	579	17,260	14,842
United States	-	-	-	-	45,432	36,561	5,569	4,471	-	-	275,550	220,702	96,926	77,816
Total	**2,645**	**2,246**	**8,721**	**7,057**	**45,432**	**36,561**	**6,273**	**5,057**	**30,521**	**29,140**	**276,169**	**221,281**	**114,186**	**92,658**
Total Proved Plus Probable														
Canada	14,265	12,214	38,953	32,033	-	-	2,765	2,302	126,290	121,857	2,146	2,029	77,389	67,196
United States	-	-	-	-	122,998	98,952	15,333	12,283	-	-	1,000,637	801,628	305,104	244,840
Total	**14,265**	**12,214**	**38,953**	**32,033**	**122,998**	**98,952**	**18,098**	**14,585**	**126,290**	**121,857**	**1,002,783**	**803,657**	**382,493**	**312,036**

Summary of Net Present Value of Future Net Revenue

Attributable to Oil and Gas Reserves (Forecast Prices and Costs)

As of December 31, 2016

	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	1,155	844	665	551	473	1,070	805	645	540	466	$13.84
United States	2,866	1,923	1,452	1,179	1,002	2,529	1,768	1,370	1,130	970	$13.25
Total	**4,021**	**2,767**	**2,117**	**1,730**	**1,475**	**3,599**	**2,573**	**2,015**	**1,670**	**1,436**	**$13.43**
Proved Developed Non-Producing											
Canada	12	4	1	1	-	8	3	1	1	-	$ 1.45
United States	8	7	6	5	4	5	6	5	4	4	$12.27
Total	**20**	**11**	**7**	**6**	**4**	**13**	**9**	**6**	**5**	**4**	**$ 5.95**
Proved Undeveloped											
Canada	98	65	44	29	19	71	48	33	22	14	$12.13
United States	1,159	635	376	226	131	681	376	218	124	62	$ 6.60
Total	**1,257**	**700**	**420**	**255**	**150**	**752**	**424**	**251**	**146**	**76**	**$ 6.93**
Total Proved											
Canada	1,264	913	710	581	492	1,150	856	678	562	481	$13.56
United States	4,033	2,566	1,834	1,410	1,137	3,216	2,150	1,593	1,259	1,035	$10.98
Total	**5,297**	**3,479**	**2,544**	**1,991**	**1,629**	**4,366**	**3,006**	**2,271**	**1,821**	**1,516**	**$11.60**
Probable											
Canada	511	271	170	117	87	373	200	128	91	68	$11.45
United States	2,554	1,161	650	407	270	1,520	671	360	214	134	$ 8.35
Total	**3,065**	**1,432**	**820**	**524**	**357**	**1,893**	**871**	**488**	**305**	**202**	**$ 8.85**
Total Proved Plus Probable											
Canada	1,775	1,184	880	698	579	1,523	1,056	806	653	549	$13.10
United States	6,587	3,727	2,484	1,817	1,407	4,736	2,821	1,953	1,473	1,169	$10.15
Total	**8,362**	**4,911**	**3,364**	**2,515**	**1,986**	**6,259**	**3,877**	**2,759**	**2,126**	**1,718**	**$10.78**

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 price forecasts supplied by McDaniel as of January 1, 2017 (and utilized by NSAI and by the Corporation in its internal evaluations for consistency in the Corporation's reserves reporting), and the following inflation and exchange rate assumptions:

	CRUDE OIL				NATURAL GAS		NATURAL GAS LIQUIDS Edmonton Par Price				
Year	**WTI(1)**	**Edmonton Light(2)**	**Alberta Heavy(3)**	**Sask Cromer Medium(4)**	**Alberta AECO Spot 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)
2017	55.00	69.80	46.50	62.80	3.40	3.40	23.30	43.50	72.80	0.0	0.750
2018	58.70	72.70	50.50	67.60	3.15	3.20	23.70	47.90	75.80	2.0	0.775
2019	62.40	75.50	54.00	70.20	3.30	3.35	26.20	49.80	78.60	2.0	0.800
2020	69.00	81.10	58.00	75.40	3.60	3.65	28.30	56.40	84.30	2.0	0.825
2021	75.80	86.60	61.90	80.50	3.90	4.00	30.30	63.40	89.80	2.0	0.850
2022	77.30	88.30	63.10	82.10	3.95	4.05	30.90	64.70	91.60	2.0	0.850
2023	78.80	90.00	64.40	83.70	4.10	4.15	31.50	65.90	93.40	2.0	0.850
2024	80.40	91.80	65.60	85.40	4.25	4.25	32.20	67.30	95.20	2.0	0.850
2025	82.00	93.70	67.00	87.10	4.30	4.30	32.90	68.60	97.20	2.0	0.850
2026	83.70	95.60	68.40	88.90	4.40	4.40	33.60	70.00	99.20	2.0	0.850
2027	85.30	97.40	69.60	90.60	4.50	4.50	34.20	71.40	101.10	2.0	0.850
2028	87.00	99.40	71.10	92.40	4.60	4.60	34.90	72.80	103.10	2.0	0.850
2029	88.80	101.40	72.50	94.30	4.65	4.65	35.60	74.30	105.20	2.0	0.850
2030	90.60	103.50	74.00	96.30	4.75	4.75	36.30	75.80	107.40	2.0	0.850
2031	92.40	105.50	75.40	98.10	4.85	4.85	37.10	77.30	109.50	2.0	0.850
Thereafter	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	0.850

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 2016, the Corporation received a weighted average price (before transportation costs, royalties, and the effects of commodity derivative instruments) of $44.84/bbl for crude oil, $15.29/bbl for natural gas liquids and $2.06/Mcf for natural gas.

UNDISCOUNTED FUTURE NET REVENUE BY RESERVES CATEGORY

The undiscounted total future net revenue by reserves category as of December 31, 2016, 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	3,550	546	1,407	206	127	1,264	114	1,150
United States	9,408	2,397	2,060	738	180	4,033	818	3,216
Total	12,957	2,943	3,467	943	307	5,297	931	4,366
Proved Plus Probable Reserves								
Canada	4,719	739	1,840	231	135	1,775	252	1,523
United States	15,103	3,871	3,018	1,398	229	6,587	1,851	4,736
Total	19,822	4,610	4,857	1,629	364	8,362	2,103	6,259

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, 2016, 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]	224,920	22.65
	Heavy Oil (including solution gas and by-products) [2]	428,603	17.17
	Tight Oil[2]	n/a	n/a
	Conventional Natural Gas (including by-products)[3]	52,258	0.72
	Shale Gas[3]	4,499	3.10
	Total	**710,280**	
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and by-products) [2]	267,213	21.97
	Heavy Oil (including solution gas and by-products) [2]	524,197	16.37
	Tight Oil[2]	n/a	n/a
	Conventional Natural Gas (including by-products) [3]	82,414	0.86
	Shale Gas[3]	5,800	2.86
	Total	**879,624**	
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]	1,247,876	20.00
	Conventional Natural Gas (including by-products) [3]	n/a	n/a
	Shale Gas[4]	585,881	1.12
	Total	**1,833,757**	
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]	1,772,631	17.91
	Conventional Natural Gas (including by-products) [3]	n/a	n/a
	Shale Gas[4]	711,305	0.99
	Total	**2,483,936**	
Total			
Proved Reserves	Light and Medium Oil (including solution gas and by-products) [2]	224,920	
	Heavy Oil (including solution gas and by-products) [2]	428,603	
	Tight Oil[2]	1,247,876	
	Conventional Natural Gas (including by-products) [3]	52,258	
	Shale Gas[3][4]	590,380	
	Total	**2,544,037**	
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and by-products) [2]	267,213	
	Heavy Oil (including solution gas and by-products) [2]	524,197	
	Tight Oil[2]	1,772,631	
	Conventional Natural Gas (including by-products) [3]	82,414	
	Shale Gas[3][4]	717,105	
	Total	**3,363,560**	

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 2017 in preparing the estimates of gross proved reserves and gross probable reserves is set forth below. Actual 2017 production (including from the Fort Berthold and Marcellus properties in the separate table below) may vary from the estimates provided by McDaniel and NSAI as the Corporation's actual development programs, timing and priorities may differ from the forecast of development by McDaniel and NSAI. Columns may not add due to rounding.

	Gross Proved Reserves							
	Canada				United States			
Product Type	Estimated 2017 Aggregate Production		Estimated 2017 Average Daily Production		Estimated 2017 Aggregate Production		Estimated 2017 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	1,781	Mbbls	4,880	bbls/day	-	Mbbls	-	bbls/day
Heavy Oil	2,860	Mbbls	7,836	bbls/day	-	Mbbls	-	bbls/day
Tight Oil	-	Mbbls	-	bbls/day	8,348	Mbbls	22,870	bbls/day
Total Crude Oil	4,641	Mbbls	12,716	bbls/day	8,348	Mbbls	22,870	bbls/day
Natural Gas Liquids	318	Mbbls	872	bbls/day	1,117	Mbbls	3,060	bbls/day
Total Liquids	4,960	Mbbls	13,588	bbls/day	9,464	Mbbls	25,930	bbls/day
Conventional Natural Gas	17,511	MMcf	47,976	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	176	MMcf	482	Mcf/day	72,271	MMcf	198,003	Mcf/day
Total	7,907	MBOE	21,664	BOE/day	21,510	MBOE	58,930	BOE/day

	Gross Probable Reserves							
	Canada				United States			
Product Type	Estimated 2017 Aggregate Production		Estimated 2017 Average Daily Production		Estimated 2017 Aggregate Production		Estimated 2017 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	53	Mbbls	146	bbls/day	-	Mbbls	-	bbls/day
Heavy Oil	106	Mbbls	289	bbls/day	-	Mbbls	-	bbls/day
Tight Oil	-	Mbbls	-	bbls/day	731	Mbbls	2,003	bbls/day
Total Crude Oil	159	Mbbls	435	bbls/day	731	Mbbls	2,003	bbls/day
Natural Gas Liquids	25	Mbbls	68	bbls/day	99	Mbbls	271	bbls/day
Total Liquids	184	Mbbls	503	bbls/day	830	Mbbls	2,275	bbls/day
Conventional Natural Gas	1,599	MMcf	4,382	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	8	MMcf	22	Mcf/day	506	MMcf	1,385	Mcf/day
Total	452	MBOE	1,237	BOE/day	915	MBOE	2,506	BOE/day

The tables below set forth McDaniel's and NSAI's estimated 2017 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 2017 production.

	Gross Proved Reserves							
	Fort Berthold				**Marcellus**			
Product Type	**Estimated 2017 Aggregate Production**		**Estimated 2017 Average Daily Production**		**Estimated 2017 Aggregate Production**		**Estimated 2017 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	7,272	Mbbls	19,923	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	7,272	Mbbls	19,923	bbls/day	-	Mbbls	-	bbls/day
Natural Gas Liquids	1,117	Mbbls	3,060	bbls/day	-	Mbbls	-	bbls/day
Total Liquids	8,389	Mbbls	22,983	bbls/day	-	Mbbls	-	bbls/day
Conventional Natural Gas	-	MMcf	-	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	5,584	MMcf	15,298	Mcf/day	64,211	MMcf	175,920	Mcf/day
Total	9,319	MBOE	25,532	BOE/day	10,702	MBOE	29,320	BOE/day

	Gross Probable Reserves							
	Fort Berthold				**Marcellus**			
Product Type	**Estimated 2017 Aggregate Production**		**Estimated 2017 Average Daily Production**		**Estimated 2017 Aggregate Production**		**Estimated 2017 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	728	Mbbls	1,993	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	728	Mbbls	1,993	bbls/day	-	Mbbls	-	bbls/day
Natural Gas Liquids	99	Mbbls	272	bbls/day	-	Mbbls	-	bbls/day
Total Liquids	827	Mbbls	2,265	bbls/day	-	Mbbls	-	bbls/day
Conventional Natural Gas	-	MMcf	-	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	496	MMcf	1,360	Mcf/day	-	MMcf	-	Mcf/day
Total	910	MBOE	2,492	BOE/day	-	MBOE	-	BOE/day

FUTURE DEVELOPMENT COSTS

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

	CANADA				UNITED STATES			
	Proved Reserves		Proved Plus Probable Reserves		Proved Reserves		Proved Plus Probable Reserves	
Year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year
				(in $ millions)				
2017	43	42	45	44	334	318	352	335
2018	47	42	51	45	346	301	427	369
2019	45	36	51	40	52	42	350	278
2020	18	14	30	22	6	4	268	192
2021	11	8	14	9	-	-	1	1
Remainder	42	22	40	23	-	-	-	-
Total	206	164	231	183	738	665	1,398	1,174

RECONCILIATION OF RESERVES

Overview

The Corporation's total gross proved plus probable reserves at December 31, 2016 were approximately 382.5 MMBOE, down approximately 6% from year-end 2015. The Corporation's gross proved plus probable crude oil and NGLs reserves were 194.3 MMBOE and represented approximately 51% of total proved plus probable gross reserves, down 6% from year-end 2015. The Corporation replaced approximately 126% of its 2016 gross production through its exploration and development program, adding 42.6 MMBOE of proved plus probable reserves, including revisions. Approximately 42% of the additions, including revisions, were crude oil and NGLs, representing the replacement of 113% of the Corporation's 2016 crude oil and NGLs production. The largest amount of crude oil reserves additions, including due to technical revisions, was in the Corporation's Fort Berthold crude oil property in North Dakota. The largest amount of conventional natural gas and shale gas reserves additions, including due to technical revisions, was in the Marcellus shale gas property, as a result of development activities and production outperformance.

The Corporation sold 37.3 MMBOE of proved plus probable reserves in 2016, all of which were associated with the divestment of certain of the Corporation's assets. Total proved plus probable conventional natural gas reserves, excluding shale gas, decreased by approximately 47% from year-end 2015. Total proved plus probable conventional natural gas and shale gas reserves decreased by approximately 6% from year-end 2015, largely due to these divestments.

The following tables reconcile the Corporation's gross crude oil and natural gas reserves from December 31, 2015 to December 31, 2016, by country and in total, using forecast prices and costs. Certain columns may not add due to rounding.

CANADIAN OIL AND GAS RESERVES

CANADA	Light & Medium Oil			Heavy Oil			Tight Oil			Natural Gas Liquids		
Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2015	13,871	3,367	17,238	31,705	9,804	41,509	-	-	-	3,274	949	4,223
Acquisitions	1,765	373	2,137	-	-	-	-	-	-	24	1	25
Dispositions	(2,885)	(845)	(3,730)	-	-	-	-	-	-	(882)	(256)	(1,138)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	100	45	145	-	-	-	-	-	-	-	-	-
Economic Factors	(606)	534	(72)	(533)	(193)	(726)	-	-	-	(173)	(69)	(242)
Technical Revisions	1,123	(829)	294	2,088	(890)	1,198	-	-	-	263	80	343
Production	(1,746)	-	(1,746)	(3,027)	-	(3,027)	-	-	-	(445)	-	(445)
December 31, 2016	**11,621**	**2,645**	**14,265**	**30,232**	**8,721**	**38,953**	**-**	**-**	**-**	**2,061**	**704**	**2,765**

CANADA	Conventional Natural Gas			Shale Gas			Total		
Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2015	183,564	53,802	237,366	4,149	1,530	5,678	80,135	23,342	103,477
Acquisitions	14,162	3,227	17,389	-	-	-	4,149	911	5,060
Dispositions	(90,343)	(29,438)	(119,781)	(2,237)	(895)	(3,133)	(19,198)	(6,157)	(25,354)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	100	45	145
Economic Factors	(4,731)	(396)	(5,127)	-	-	-	(2,101)	207	(1,894)
Technical Revisions	20,012	3,325	23,337	(128)	(15)	(143)	6,789	(1,089)	5,700
Production	(26,894)	-	(26,894)	(256)	-	(256)	(9,744)	-	(9,744)
December 31, 2016	**95,769**	**30,521**	**126,290**	**1,527**	**619**	**2,146**	**60,130**	**17,260**	**77,389**

UNITED STATES OIL AND GAS RESERVES

UNITED STATES	Light & Medium Oil			Heavy Oil			Tight Oil			Natural Gas Liquids		
Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2015	-	-	-	-	-	-	86,202	45,051	131,253	7,430	4,044	11,474
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	(6,034)	(3,680)	(9,713)	(640)	(366)	(1,007)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	5,429	13,810	19,239	589	1,540	2,129
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	1,182	(9,749)	(8,566)	3,662	351	4,013
Production	-	-	-	-	-	-	(9,214)	-	(9,214)	(1,277)	-	(1,277)
December 31, 2016	**-**	**-**	**-**	**-**	**-**	**-**	**77,566**	**45,432**	**122,998**	**9,764**	**5,569**	**15,333**

UNITED STATES	Conventional Natural Gas			Shale Gas			Total		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2015	-	-	-	620,932	336,758	957,690	197,120	105,221	302,341
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	(4,873)	(2,670)	(7,543)	(7,486)	(4,491)	(11,977)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	36,268	27,948	64,216	12,063	20,008	32,071
Economic Factors	-	-	-	(30,053)	1,998	(28,056)	(5,009)	333	(4,676)
Technical Revisions	-	-	-	183,321	(88,484)	94,837	35,398	(24,145)	11,253
Production	-	-	-	(80,507)	-	(80,507)	(23,909)	-	(23,909)
December 31, 2016	**-**	**-**	**-**	**725,087**	**275,550**	**1,000,637**	**208,178**	**96,926**	**305,104**

TOTAL OIL AND GAS RESERVES

TOTAL	Light & Medium Oil			Heavy Oil			Tight Oil			Natural Gas Liquids		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2015	13,871	3,367	17,238	31,705	9,804	41,509	86,202	45,051	131,253	10,704	4,993	15,697
Acquisitions	1,765	373	2,137	-	-	-	-	-	-	24	1	25
Dispositions	(2,885)	(845)	(3,730)	-	-	-	(6,034)	(3,680)	(9,713)	(1,522)	(622)	(2,145)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	100	45	145	-	-	-	5,429	13,810	19,239	589	1,540	2,129
Economic Factors	(606)	534	(72)	(533)	(193)	(726)	-	-	-	(173)	(69)	(242)
Technical Revisions	1,123	(829)	294	2,088	(890)	1,198	1,182	(9,749)	(8,566)	3,925	430	4,356
Production	(1,746)	-	(1,746)	(3,027)	-	(3,027)	(9,214)	-	(9,214)	(1,722)	-	(1,722)
December 31, 2016	**11,621**	**2,645**	**14,265**	**30,232**	**8,721**	**38,953**	**77,566**	**45,432**	**122,998**	**11,825**	**6,273**	**18,098**

TOTAL	Conventional Natural Gas			Shale Gas			Total		
Factors	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2015	183,564	53,802	237,366	625,081	338,288	963,368	277,255	128,563	405,818
Acquisitions	14,162	3,227	17,389	-	-	-	4,149	911	5,060
Dispositions	(90,343)	(29,438)	(119,781)	(7,110)	(3,566)	(10,676)	(26,683)	(10,648)	(37,331)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	36,268	27,948	64,216	12,163	20,053	32,216
Economic Factors	(4,731)	(396)	(5,127)	(30,053)	1,998	(28,056)	(7,110)	540	(6,570)
Technical Revisions	20,012	3,325	23,337	183,193	(88,499)	94,694	42,187	(25,234)	16,953
Production	(26,894)	-	(26,894)	(80,763)	-	(80,763)	(33,653)	-	(33,653)
December 31, 2016	**95,769**	**30,521**	**126,290**	**726,614**	**276,169**	**1,002,783**	**268,307**	**114,186**	**382,493**

UNDEVELOPED RESERVES

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

Proved Undeveloped Reserves

	Crude Oil						
Year[(1)]	Light & Medium	Heavy	Tight	NGLs	Conventional Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
2014	398	1,590	3,051	293	13,374	63,033	18,067
2015	82	1,390	1,194	109	56	16,776	5,579
2016	100	-	3,492	391	-	6,080	4,996

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

Probable Undeveloped Reserves

	Crude Oil						
Year[1]	Light & Medium	Heavy	Tight	NGLs	Conventional Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
2014	181	1,568	2,043	183	6,536	24,014	9,067
2015	37	558	6,296	573	33	37,948	13,794
2016	45	-	13,104	1,468	-	26,468	19,028

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

The Corporation attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information, and the optimization of existing fields. The Corporation has been active for the last several years in drilling and developing these undeveloped reserves and the Corporation expects this to continue. Despite the current reduced drilling activity level, development of the proved undeveloped reserves is now forecast to occur continuously over the next three years, while development of the proved plus probable undeveloped reserves is forecast to occur over the next five 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.

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

PROVED AND PROBABLE RESERVES NOT ON PRODUCTION

The Corporation has approximately 1.4 MMBOE of proved plus probable reserves which are capable of production but which, as of December 31, 2016, were not on production. These reserves have generally been non-producing for periods ranging from a few months to more than five years. The majority of these reserves are related to reserves volumes from recently drilled wells which require the completion of infrastructure before production can begin. A minor portion of these reserves is related to commercially producible volumes that are not producing due to production requirements of other reserves formations or zones in the same well bore. These reserves relate to the longer term non-producing periods.

Supplemental Operational Information

SAFETY AND SOCIAL RESPONSIBILITY

The Corporation has adopted a Safety and Social Responsibility Policy ("**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, and 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 that support its sustainability goals.

The S&SR Policy articulates the Corporation's commitment to protecting the health and safety of all persons and communities involved in, or affected by, its business activities. Specifically, the S&SR Policy outlines that the Corporation will: (i) promote and support a culture in which all employees and contractors share ownership of a workplace where no one gets injured; (ii) provide the resources, equipment and training needed to ensure everyone complies with its health and safety programs; and (iii) 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 articulates the Corporation's commitment to the environment and states that the Corporation will: (i) proactively manage its impact on the environment and consider innovative improvement opportunities; (ii) 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; (iii) improve its water and land use practices; (iv) limit the waste it generates; (v) prevent and manage environmental releases; (vi) provide transparent disclosure; and (vii) provide resources and training to meet its environmental commitments.

The Corporation's commitment to building meaningful and transparent relationships with its stakeholders is articulated 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.

Health and Safety

The Corporation's combined (employee/contractor) recordable injury frequency rate for 2016 was 0.81 injuries per 200,000 man hours, a decrease from the rate of 1.24 recorded in 2015. The Corporation's employee recordable injury frequency rate of 0.37 injuries per 200,000 man hours in 2016 also decreased from 0.99 injuries per 200,000 man hours in 2015. The Corporation's total contractor recordable injury frequency of 1.32 injuries per 200,000 man hours in 2016 decreased from 1.48 injuries per 200,000 man hours in 2015. The Corporation recorded two lost-time injuries in 2016, a decrease from three recorded in 2015. The Corporation had zero employee or contractor fatalities in 2016 and 2015.

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; and

- monitor performance to ensure that its operations comply with all legal obligations and its internally-imposed standards.

The health and safety component of the S&SR management system is reviewed annually for continuous improvement opportunity. Every three years, the Health and Safety Management System is subject to a third-party audit utilizing the Enform Certificate of Recognition ("**COR**") Audit Protocol. Annual maintenance audits against the COR Audit Protocol are conducted each year. In 2016, the Corporation successfully renewed its COR certification.

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

Environment

The Corporation is committed to meeting its responsibilities to protect the environment through a variety of programs and actively monitors its operations for compliance with all relevant and applicable environmental regulations and industry best practices. The Corporation engages in the following activities:

- Site abandonment, remediation, and reclamation capital expenditures for the Corporation's Canadian and United States properties in 2016 totaled $8.4 million ($5.9 million on operated properties and $2.5 million on non-operated properties). The Corporation received 41 reclamation certificates from regulatory agencies in 2016 by returning sites to their previous equivalent land capability;

- The Corporation completes third-party environmental compliance audits designed to ensure compliance with environmental legislation and regulations. In 2016, three environmental compliance audits were completed;

- The Corporation completes third-party loss prevention audits to identify and evaluate the risk exposures associated with production equipment, process operations, utility supply systems and natural hazards. In 2016, two facilities were audited. 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 our facilities, mitigating the potential exposure to financial loss associated with property damage and production loss, and ensuring the adequacy of our relevant insurance coverage;

- Government regulators conducted 238 inspections of the Corporation’s field operations in the United States and Canada in 2016, an increase from the 148 government regulator inspections conducted in 2015. The percentage of noncompliant field inspections received by the Corporation in 2016 was 7%, an improvement from the 15% noncompliant field inspections received in 2015;

- The Corporation continues its internal facility inspection program and completed 25 inspections at major Canadian facilities in 2016. The average score of compliance resulting from the internal inspection program in 2016 was 93% compared to 85% in 2015;

- The Corporation conducts its internal monthly site inspection program at its U.S. and Canadian locations, the focus of which is to assess environmental, regulatory, and general housekeeping items. Findings from the monthly site inspection program are recorded in the Corporation’s internal Sustainability Information Management System;

- The Corporation conducts annual property reviews with specific risk reduction objectives. The Corporation also continues to manage risk through the 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 2016 to be approximately 645,950 carbon dioxide equivalent tonnes per year, which is 7% less than the Corporation's direct emissions in 2015 of 696,953 carbon dioxide equivalent tonnes per year. The estimated numbers will be adjusted as additional data becomes available. In 2016, the Corporation completed 24 fugitive emissions surveys at its Canadian facilities and 66 at its U.S. production pad facilities to detect losses from leaks and vents, and is working to repair identified leaks.

Greenhouse gas regulations have been enacted in British Columbia, Alberta and at the federal level in Canada and the United States. In 2016, the Corporation’s only operations with an active carbon tax was in the jurisdiction of British Columbia. The total carbon tax paid was approximately $0.7 million in 2016. In addition, the Corporation is required to report third-party verified greenhouse gas emissions annually to the government of British Columbia under the *Greenhouse Gas*

Reduction (*Cap and Trade) Act* (British Columbia) (the "**BCCTA**"). The Corporation is not subject to the Canadian greenhouse gas emissions reporting requirement as it does not currently operate facilities above the 50,000 tonnes of carbon dioxide equivalent per year per facility threshold. However, the Corporation is subject to the reporting requirement in the United States 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, 2016 for the 2015 operational year. The report for the 2016 operational year will be submitted on March 31, 2017. For more information on the environmental regulation applicable to the Corporation, see "*Industry Conditions – Environmental Regulation"*.

Some of the Corporation's operations use hydraulic fracturing techniques to stimulate the production of oil and natural gas from geological formations which were previously unproductive. Hydraulic fracturing involves the injection of pressurized fluids, sand, and small amounts of additives into a well bore. The practice of hydraulic fracturing associated with drilling in shale formations is the subject of significant focus among some environmentalists and regulators. Concerns have been raised by local, state, provincial, and federal levels of government in Canada and the U.S. over the potential hazards and environmental impact associated with the use of hydraulic fracturing. The Corporation strives to comply with all current Canadian and U.S. regulations and adheres to best practices and industry standards for well construction and hydraulic fracturing operating practices. Although the Corporation proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the United States impose more stringent hydraulic fracturing compliance requirements.

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 improvement targets. The Corporation believes that by monitoring S&SR 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 third party liability, property damage, business interruption, terrorism, cyber-attacks, pollution and well control. In addition, liability coverage is also carried for the directors and officers of the Corporation.

PERSONNEL

As at December 31, 2016, the Corporation employed a total of 472 persons, including full-time benefit employees and payroll consultants, 340 of whom were in Canada and 132 of whom were in the United States.

Description of Capital Structure

The authorized capital of the Corporation consists of an unlimited number of Common Shares and a number of preferred shares, issuable in series ("**Preferred Shares**"), which are limited to an amount equal to not more than one-quarter of the number of issued and outstanding Common Shares at the time of the issuance of any such Preferred Shares. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares. Copies of the Corporation's articles of amalgamation, 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 of the Corporation, as amended and restated on May 11, 2012, contain provisions facilitating payment of dividends on Common Shares through issuance of Common Shares in circumstances where the board of directors discloses, and a shareholder of the Corporation validly elects to receive, payment of dividends, in whole or in part, in the form of Common Shares. See "*Dividends – Stock Dividend Program*".

PREFERRED SHARES

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

SHAREHOLDER RIGHTS PLAN

The continuation and amendment and restatement of the Shareholder Rights Plan was approved by shareholders of the Corporation, including by requisite number of the Corporation's "Independent Shareholders" (as defined in the Shareholder Rights Plan), at the annual meeting held on May 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 in 2019, failing which it will expire at the end of such meeting. The Shareholder Rights Plan, under which Computershare Trust Company of Canada acts as rights agent, generally provides that, following the acquisition by any person or entity of 20% or more of the issued and outstanding Common Shares (except pursuant to certain permitted or excepted transactions) and upon the occurrence of certain other events, each holder of Common Shares, other than such acquiring person or entity, shall be entitled to acquire Common Shares at a discounted price. The Shareholder Rights Plan is similar to other shareholder rights plans adopted in the energy sector. A copy of the Shareholder Rights Plan was filed on May 6, 2016 as an "Other securityholders documents" on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov, and is available on the Corporation's website at www.enerplus.com under "Corporate Governance".

SENIOR UNSECURED NOTES

Enerplus has issued Senior Unsecured Notes, of which US$533 million and CDN$30 million principal amounts were outstanding at December 31, 2016. 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$110 million	7.97%	June 18 and December 18	June 18, 2021	Principal payments required in five equal annual installments beginning June 18, 2017

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

BANK CREDIT FACILITY

As of December 31, 2016, the Corporation had $23.2 million drawn on its $800 million senior unsecured, covenant-based credit facility with a syndicate of financial institutions maturing October 31, 2019.

For a description of the Bank Credit Facility, see Note 7 to the Corporation's audited consolidated financial statements for the year ended December 31, 2016. 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 has currently established a dividend policy of paying monthly dividends to holders of Common Shares. The dividend record date is on or about the last business day of each calendar month and the corresponding dividend payment date is on or about the 15th day of the following month. **However, any decision to pay dividends on the Common Shares will be made by the Corporation's board of directors on the basis of the relevant conditions existing at such future time, and there can be no guarantee that the Corporation will maintain its current dividend policy. Dividend amounts 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 on the Corporation's Common Shares are variable*". Monthly cash dividends paid to U.S. resident shareholders are converted to U.S. dollars based upon the actual Canadian to U.S. dollar exchange rate on the dividend payment date and, accordingly, shareholders that are not resident in Canada are subject to foreign exchange rate risk on such payments.

The table below sets forth the dividends paid or declared by the Corporation in 2014, 2015, 2016 and January through March of 2017:

Month	2017	2016	2015	2014
January	$ 0.01	$ 0.03	$ 0.09	$ 0.09
February	0.01	0.03	0.09	0.09
March	0.01	0.03	0.09	0.09
April	N/A	0.01	0.05	0.09
May	N/A	0.01	0.05	0.09
June	N/A	0.01	0.05	0.09
July	N/A	0.01	0.05	0.09
August	N/A	0.01	0.05	0.09
September	N/A	0.01	0.05	0.09
October	N/A	0.01	0.05	0.09
November	N/A	0.01	0.05	0.09
December	N/A	0.01	0.03	0.09

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

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

STOCK DIVIDEND PROGRAM

Effective May 11, 2012, the Corporation implemented a stock dividend program pursuant to which shareholders of the Corporation were able to elect to receive dividends in the form of Common Shares, instead of receiving a cash dividend, issued at a deemed price of 95% of the five day weighted average trading price of the Common Shares on the TSX immediately prior to the applicable dividend payment date. Effective with the April 2014 dividend, the Corporation elected to eliminate the 5% discount applied to determine the number of 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 oil and natural gas industry is subject to extensive controls and regulation governing its operations (including land tenure, exploration, development, production, refining, transportation, marketing, remediation, abandonment and reclamation) imposed by legislation enacted by various levels of government. The oil and natural gas industry is also subject to agreements among the various federal, provincial and state governments with respect to pricing and taxation of oil and natural gas. Although it is not expected that any of these controls, regulations or agreements will affect the Corporation's operations in a manner materially different than they would affect other oil and gas issuers in similar operating areas, the controls, regulations and agreements should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

The Corporation owns oil and natural gas properties and related assets in Canada (primarily in Alberta, Saskatchewan and British Columbia) and in Montana, North Dakota, Pennsylvania and Colorado in the United States. The Corporation's oil and natural gas operations are regulated by administrative agencies under statutory provisions of the provinces and states where such operations are conducted, and by certain agencies of the federal government for operations on U.S. federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. The Corporation's operations are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, 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 in both Canada and 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 Canada and the Unites States, producers of crude oil negotiate sales contracts directly with crude oil purchasers. Most agreements are linked to global oil prices, which are set by daily, weekly and monthly physical and financial transactions for crude oil around the world. Those prices are primarily based on worldwide fundamentals of supply and demand. Specific prices depend, in part, on crude oil quality, prices of competing fuels, distance to markets, access to downstream transportation, the value of refined products, the supply/demand balance and other contractual terms.

In Canada and the United States, producers of natural gas are free to negotiate prices and other terms with purchasers, provided that export contracts meet certain criteria prescribed by the National Energy Board and the Government of Canada or, in relation to U.S. exports, restrictions on export licenses imposed by the United States Department of Energy. The price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to 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. Since mid-2014, crude oil and natural gas prices experienced significant decline and have fluctuated in response to a variety of factors including, among others, the increase in supply of crude oil and the decision by the Organization of Petroleum Exporting Countries to decrease production levels in response to such increase. See "*Risk Factors – Low or volatile oil and natural gas prices could have a material adverse effect on the Corporation's results of operations and financial condition*". In addition, crude oil and natural gas producers in North America currently receive significantly discounted prices for their production relative to certain international prices as a result of constraints on the ability to transport and sell their products to national, and in some cases, international markets due to lack of infrastructure capacity. 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 oil and natural gas production*".

ROYALTIES AND INCENTIVES

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

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

LAND TENURE

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

Crude oil and natural gas located in the U.S. is predominantly owned by private owners. The 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 may generally be continued after the initial term provided certain minimum levels of exploration or production have been achieved and all lease rentals have been timely paid, subject to certain exceptions. To develop minerals, including oil and natural gas, it is necessary for the mineral estate owner to have access to the surface estate. Under common law, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each jurisdiction has developed and adopted its own statutes that operators must follow both prior to drilling 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 apply restrictions and prohibitions regarding disturbances and releases or emissions of various substances produced or utilized in association with oil and gas industry operations. Environmental laws may impose remediation obligations with respect to a property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused release of the substance and any past or present owner, tenant, or other person in possession of the site. In addition, legislation and regulation requires that well, pipeline and facility sites are abandoned and reclaimed to the satisfaction of the applicable authorities. Compliance with these requirements can involve significant expenditures. A breach of such requirements may result in the imposition of material fines and penalties, the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage or the issuance of clean-up orders. See "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, as well as public opposition and activism*".

In British Columbia, energy projects may be subject to review pursuant to the provisions of the *Environmental Assessment Act*, which rolls the previous processes for the review of major energy projects into a single environmental assessment process that contemplates public participation in the environmental review. Other environmental protection and management measures, including reclamation, are governed by the *Oil and Gas Activities Act* and the *Environmental Management Act*.

In Alberta, the Alberta Energy Regulator ("**AER**") is now 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 *Public Lands Act* and the *Mines and Minerals Act,* the *Water Act* and the *Environmental Protection and Enhancement Act* by oil and gas operators and imposes penalties for violations, which may be significant.

In Saskatchewan, environmental regulation is governed by the *Saskatchewan Environmental Code*, which prescribes applicable levels of emissions without mandating express measures to achieve such levels. The Corporation's strives to carry out its activities and operations in compliance with all relevant and applicable Saskatchewan environmental regulations.

In 2008, the Province of British Columbia instituted a carbon tax that applies to all fuel users and producers in the province, as well as the BCCTA, which requires third party verified greenhouse gas emissions to be reported annually. See "*Supplemental Operational Information – Safety and Social Responsibility – Environment*". The Province of British Columbia is in discussions with stakeholders and partners of the Western Climate Initiative to develop an Emissions Trading Regulation and an Offsets Regulation under the BCCTA to price carbon and to reduce greenhouse gas emissions of regulated emitters through a regional cap and trade program. The Corporation is unable to estimate the future potential compliance costs of these pending regulations without a carbon price or an allocation of emission allowances. However, given the Corporation's current hydrocarbon production levels in British Columbia and a current price of carbon offsets in the marketplace of approximately $30 per tonne of carbon dioxide equivalent, the Corporation does not expect such costs to be material.

The Province of Alberta instituted the *Climate Leadership Act* in 2016 (the "**Alberta Climate Leadership Act**"), which imposes a carbon tax for all on-site combustion emissions. The carbon tax will be $30 per tonne of carbon dioxide equivalent emissions, and goes into effect beginning in 2023. In 2017, the Corporation will potentially be subject to increased costs due to the carbon tax coming into effect for electricity generators. In addition, the Province of Alberta has established a reduction goal of 45% for methane gas emissions by 2025, and will mandate prescriptive measures to reduce methane in methane venting equipment, which include increased fugitive leak detection inspections. This is in alignment with federal methane emissions reduction regulations that are currently in draft form. The Corporation may incur increased costs to facilities due to equipment retrofits, increased measurement and reporting work, and higher frequency of fugitive leak inspections. The *Alberta Climate Leadership Act* has set emission reduction targets for large emitters (e.g., 100,000 tonnes of carbon dioxide per year at a single facility). Currently, the Corporation does not operate any facility classed within this large emitter category.

The Province of Saskatchewan has passed, but not yet proclaimed, *The Management and Reduction of Greenhouse Gases Act*, which would require regulated emitters to report and reduce their greenhouse gas emissions below a prescribed amount below their individual baseline emission level. The Corporation does not operate any facility classed within the regulated emitter category in Saskatchewan based on the 50,000 tonne per year carbon dioxide equivalent emissions threshold.

In the United States, oil and gas operations are regulated at the federal, state, county, and tribal levels of government. At the federal level, well planning and permitting is primarily regulated by the 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, imposed by several state agencies regulating oil and gas activities. In addition to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, water quality, 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), 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.

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.

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

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

In July of 2014, the North Dakota Industrial Commission ("**NDIC**") finalized a 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 regulations timeframe. 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 in* *production, or curtailments in the Corporation's production due to environmental regulations, volatility in commodity prices and third party operational business practices which could have an adverse effect on results of operations and financial condition*". The Corporation received no NDIC orders to curtail crude oil production in 2016 and has consistently exceeded regulatory established gas capture rates since January 2015.

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 was in compliance with these requirements in 2016.

In 2016, the U.S. EPA finalized three air quality regulations potentially affecting the Corporation. 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.

In addition, on November 17, 2016, BLM finalized revisions to various rules pertaining to the measurement of oil and gas and site security requirements, which had not been updated for nearly 30 years. The Corporation has been active, along with its industry partners, in these rulemaking processes and does not expect significant business impacts from these changes. BLM also finalized new rules on the venting and flaring of produced gas on November 18, 2016, which impose further limits on natural gas flaring, require additional gas leak detection and repair, as well as provide further clarification on associated royalty obligations. The rules are currently the subject of lawsuits from multiple industry organizations and governmental entities, and are expected to be addressed in late 2017. Many of the requirements set out in the rules are duplicative of existing state and U.S. EPA requirements that are already applicable to the Corporation.

After the United Nations Framework Convention on Climate Change ("**UNFCCC**") meeting in Copenhagen in December 2009, the governments of the United States and Canada committed to a 17% reduction in greenhouse gas emissions by 2020 relative to a 2005 baseline. The Government of Canada is working towards this target on a sector by sector basis, but has yet to finalize regulations pertaining to the oil and gas sector. During the UNFCCC Paris 2015 meetings, the governments of the U.S. and Canada restated their commitment to emission reductions that were in-line with the targets previously set. Furthermore, 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 greenhouse gas levels in the atmosphere. This commitment to limit warming may increase provincial, state and federal greenhouse gas regulatory rigour as country-level emissions will be reviewed periodically in subsequent meetings to assess alignment with the targets agreed upon.

In 2016, the Canadian federal government announced intentions to implement a federal carbon tax applicable to hydrocarbon combustion and methane emissions. The tax is proposed to begin in 2018 at rate of $10/tonne and would increase by $10/tonne per year to a maximum rate of $50/tonne in 2022. The rate would be paused at $30/tonne in 2020 to undergo a formal reassessment. Specifics regarding implementation and harmonization with existing provincial carbon pricing have yet to be announced. The federal plan would supersede provincial jurisdictions with less stringent or non-existent carbon reduction mechanisms, such as Saskatchewan. The federal tax would be applicable to electricity generation.

The Canadian federal government has also announced a methane reduction strategy with proposed implementation in two stages: Stage 1 (leak detection and repair, completions and compressors) in 2020 and Stage 2 (venting and pneumatics) in 2023. Although there would likely be significant costs associated with compliance, more details regarding the proposed strategy are required before impacts thereof on the Corporation's operations can be determined.

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, as well as public opposition and activism*" and "*Risk Factors – Government regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs*".

WORKER SAFETY

The Corporation's oilfield operations must be carried out in accordance with safe work procedures, rules and policies contained in applicable safety legislation. Such legislation requires that every employer ensures the health and safety of all persons at any of its work sites and all workers engaged in the work of that employer. The legislation, which provides for incident reporting procedures, also requires that every employer ensure that all of its employees are aware of their duties and responsibilities under the applicable legislation. Penalties under applicable occupational health and safety legislation include significant fines and incarceration. 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, should be carefully considered before investing in the Corporation. Each of these risks may negatively affect the trading price of the Common Shares or the amount of dividends that may, from time to time and at the discretion of the Corporation's board of directors, be declared and paid by the Corporation to its shareholders. As stated above, references to "natural gas" refer to both natural gas and shale gas, unless otherwise specified.

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

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

Further declines in crude oil and/or natural gas prices, or prolonged continuation of the current low commodity price environment, may have a material adverse effect on the Corporation's operations, financial condition, borrowing ability, levels of reserves and resources and the level of expenditures for the development of the Corporation's oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting the Corporation's production volumes, or its desire to market its production in unsatisfactory market conditions. Alternatively, due to regulatory or contractual obligations, the Corporation may be required to develop certain properties in order 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 production.

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

Higher capital or operating costs associated with the Corporation's operations will directly impact our capital efficiencies and/or decrease the amount of the Corporation's cash flow, which could result in a lower price of its Common Shares. Capital costs of completions, specifically the costs of proppant, 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 2017 capital and operating costs protected with existing agreements, changing regulatory conditions, such as those in the United States requiring that certain raw materials, including steel, for United States businesses be sourced from the United States, may result in higher than expected supply costs on a portion of the Corporation's costs.

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 personnel, access to drilling rigs, service rigs and other equipment, 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 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.

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

Higher than expected declines in production, or curtailments in the Corporation's production due to environmental regulations, volatility in commodity prices and third party operational business practices could have an adverse effect on results of operations and financial condition.

The Corporation may also 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.

These 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. With regard to curtailment, although regional pipeline capacity has increased over the past several years, sales gas infrastructure capacity in northeastern Pennsylvania remains constrained relative to the amount of natural gas that can be produced. Combined with the ongoing volatility in natural gas prices, the Corporation may continue to be subject to discounted prices and, therefore, the risk of potential production curtailments due to price remains.

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

Further declines in, or continued low oil and natural gas prices may result in a significant reduction in earnings or cash flow, which could lead the Corporation to increase drawn amounts 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 2016 and, accordingly, it currently expires on October 31, 2019. There can be no assurance that such a renewal will be available on favourable terms or that all of the current lenders under the facility will renew at their current commitment levels. If this occurs, the Corporation may need to obtain alternate financing. Any failure of a member of the lending syndicate to fund its obligations under the Bank Credit Facility or to renew its commitment in respect of such Bank Credit Facility, or failure of the Corporation to obtain replacement financing or financing on favourable terms, may have a material adverse effect on the Corporation's business and 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.

During 2016, the Corporation made aggregate principal repayments on Senior Unsecured Notes of US$267 million, at a discount. The Corporation did not have principal repayments due during 2016; however, the Corporation will be required to repay US$22 million in five equal annual installments, beginning in June of 2017, as part of the Corporation's scheduled principal repayments on its Senior Unsecured Notes. See "*Description of Capital Structure – Senior Unsecured Notes*" for repayment terms on existing Senior Unsecured Notes. The repayment of the Senior Unsecured Notes may require the Corporation to obtain additional financing, which may not be available or may be available on unfavourable terms.

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

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

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

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

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

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

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

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.

Under U.S. GAAP, the net deferred tax assets of a corporation is 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 reserves, undiscounted, using December 30, 2016 benchmark forward prices for 2017, held constant, 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.

As the ceiling test is based on trailing twelve month actual prices, which have declined since mid-2014, the Corporation incurred non-cash property impairments of approximately $301.2 million (before tax) in 2016. Under U.S. GAAP, a previously recorded valuation allowance can be reversed if the estimate of future taxable income increases. In 2016, the benchmark forward prices increased from 2015; therefore, the Corporation had a non-cash recovery of $266.9 million on the reversal of a portion of the valuation allowance recorded in 2015.

With commodity prices remaining at current levels, or further declining, 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. With commodity prices remaining at current levels, or further declining, there remains a risk for additional write-downs under U.S. GAAP.

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."*

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

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the abilities of the operators of the Corporation's properties. In 2016, approximately 47**%** of the Corporation's production was from properties operated by third parties. This results in significant reliance on third party operators in both the operation and development of such properties and control over capital expenditures relating thereto. The timing and amount of capital required to be spent by the Corporation may differ from the Corporation's expectations and planning, and may impact the ability 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. To the extent a third party operator fails to perform its duties properly, faces capital or liquidity constraints or becomes insolvent, the Corporation's results of operations will be negatively impacted.

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

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 and foreign exchange exposure, it may forego the benefits it would otherwise experience if commodity prices were to increase or if the Canadian dollar were to weaken relative to the U.S. dollar. In addition, the Corporation's commodity and foreign exchange hedging activities, and changing bank regulations that may limit market 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 also entered into hedging arrangements to settle future payments under its equity-based long term incentive programs, which could result in the Corporation suffering losses to the extent the hedged costs of such arrangements exceed the actual costs that would otherwise be payable at the time of settlement.

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.

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 oil and natural gas production.

The Corporation's business depends in part upon the availability, proximity, and capacity of oil and natural gas gathering systems, pipelines and/or rail transportation systems and processing facilities to provide access to markets for its production. Canadian federal and provincial, as well as U.S. federal and state, regulation of oil and gas production, processing and transportation, could adversely affect the Corporation's ability to produce and market oil and natural gas. Special interest groups could also oppose infrastructure development resulting in a delay, or even the cancellation 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 local or tribal 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

As new resource plays are developed, they generally experience a sharp increase in the volume of oil and natural gas production 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 midstream companies are able to construct adequate gathering infrastructure to allow for the required capture of natural gas production associated with the development of crude oil properties may have an impact on the Corporation’s ability to increase crude oil production in the region. Additionally, as exploration and drilling on the Corporation's properties 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.

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

SALES PIPELINES AND RAIL TRANSPORTATION SYSTEMS

Oil and natural gas producers in North America, and particularly in Canada and in the Marcellus region of the United States, currently receive significantly discounted prices 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 the 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 sales pipelines in

Alberta, British Columbia and Pennsylvania, as well as on a number of proposed crude oil pipeline expansion projects in Western Canada and the United States. 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. Also, there may be operational or economic reasons, including but not limited to maintenance activities, for curtailing transportation capacity. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. To the extent that the transportation capacity becomes insufficient in areas where the Corporation operates, the Corporation may have to defer the development of, 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, rail (after title is transferred to buyer's name) and trucking transportation, all subject to various risks of cost escalation and new costs. In certain regions the Corporation is currently dependent upon only one means of transportation. With respect to rail transportation, there may be future incremental costs associated with transporting, and there is a risk that access to rail transport may be constrained, depending upon changes made to existing rail transport regulations. More stringent government regulations concerning the usage of certain types of tank cars that transport crude oil and NGLs by rail in Canada and the United States 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 or natural gas 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 shut down or curtailment 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 in order to separate the liquids stream into individual saleable products. The Corporation and the industry as a whole rely on the addition of adequate fractionation capacity to ensure the timely and economic processing of its liquids and the continued production of its crude oil and natural gas associated with those liquids. Limited natural gas processing capacity in certain regions may result in producers not realizing the full price for NGLs associated with their natural gas production.

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

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, while offering limited relief to the Corporation's cost structure, when its costs are incurred in Canadian dollars. However, 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. The value of the Canadian dollar has decreased significantly compared to the U.S. dollar since mid-2014 and may decrease further in the future. 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 further 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 15(b) to the Corporation's audited consolidated financial statements for the year ended December 31, 2016.

Regulatory requirements may impede the Corporation's ability to divest properties.

Recent regulatory changes in Alberta and Saskatchewan have increased the minimum corporate liability rating required of purchasers of oil and natural gas properties. As a result, the potential number of parties able to acquire the Corporation's non-core assets has been reduced, the Corporation may not be able to realize full value for such assets, or transactions may involve greater risk and complexity.

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 future acquisitions. The risk factors set forth in this Annual Information Form relating to the oil and natural gas business and the operations, reserves and resources of the Corporation apply equally in respect of any future properties or assets that the Corporation may acquire. The Corporation generally conducts certain due diligence in connection with acquisitions, but there can be no assurance that the Corporation will identify all of the potential risks and liabilities related to the subject properties.

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

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

The Corporation may also from time to time 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 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 may incur additional general and administrative compliance costs and may have restricted access to capital markets for a period of time until it has the required approvals in place from the SEC.

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

The oil and gas industry operates under federal, provincial, state and municipal legislation and regulation governing such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, the imposition of specific drilling obligations, control over the development and abandonment of fields (including restrictions on production), and possibly expropriation or cancellation of contract rights. See "*Industry Conditions*". To the extent that the Corporation fails to comply with applicable government regulations or regulatory approvals, the Corporation may be subject to 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 noncompliance, warnings, orders, administrative sanctions, and prosecution.

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

Additionally, various levels of Canadian and U.S. governments are considering, or have implemented, legislation to reduce emissions of greenhouse gases, including volatile organic compounds. See "*Industry Conditions – Environmental Regulation*" for a description of these initiatives. Because the Corporation's operations emit various types of greenhouse gases, such new legislation or regulation could increase the costs related to operating and maintaining the Corporation's facilities, and could require it to install new emission controls on its facilities, acquire allowances for its greenhouse gas emissions, pay taxes, fees and other penalties related to its greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. 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, as well as public opposition and activism.

GENERAL

The oil and natural gas industry elicits concerns over 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, or the Corporation's default under applicable legislation, may result in increased costs due to delays or damage and, for breaches, 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 that would require significant reductions in greenhouse gas emissions. Failure to comply with such regulations and laws can result in significant increases in costs, penalties or loss of operating licenses. Further, the business of exploration, development and production of oil and natural gas wells and facilities is subject to the risks and hazards associated with such operations. These include, but are not limited to, blowouts, fire, explosion, environmental releases (including sour gas), and other safety hazards, which could result in significant damage to the Corporation's property, personal injury, loss of life and liability to regulators or third parties. Although the actual form such legislation or regulation may take is largely currently unknown, the implementation of more stringent environmental legislation or regulatory requirements may result in additional costs for oil and natural gas producers such as the Corporation, and such costs may be significant.

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

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

RISKS RELATING TO FRACTURING

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

It is anticipated that federal, provincial and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While the Corporation is unable to predict the impact of any potential regulations upon its business, the implementation of new laws, regulations or permitting regulations with respect to water usage or 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.

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

The Corporation’s participation in projects that are more exploration-oriented in nature than the Corporation has historically participated in, increases the risk that the Corporation's expenditures on land, seismic and drilling may not provide economic returns. To the extent the Corporation acquires properties or assets with a higher exploration risk profile, the risk associated with such acquisitions and the future development of those assets has greater uncertainty.

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

Tax laws, including those that may affect the taxation of the Corporation, or other laws or government incentive programs relating to the oil and gas industry, may be changed, or interpreted in a manner that adversely affects the Corporation and its securityholders. Canadian, U.S. and foreign tax authorities and applicable tax treaties having jurisdiction over the Corporation (whether as a result of the Corporation's operations or financing structures) may change or interpret applicable tax laws or 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 that have 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.

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 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 new focus on exploration, may draw increased attention from shareholder activists who oppose the strategy of the Corporation, including its operation of the business or its plans for development, 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 market-based factors 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, or dividends paid to its shareholders. The market price of the Common Shares is, therefore, sensitive to a variety of market-based factors, including, but not limited to, the inclusion, or removal, of 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 these market-based factors 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 Share 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 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. Although the Corporation carries liability, business interruption, terrorism, cyber-attack, and property insurance in respect of such matters, there can be no assurance that insurance proceeds will be received or, if received, be adequate to cover all losses resulting from such events, or that the lost production will be restored in a timely manner. The Corporation may become liable for damages arising from these events against which it cannot insure, or against which it may elect not to insure because of high premium costs, or other reasons. While the Corporation has both safety and environmental policies in place to protect its operators and employees, and to meet regulatory requirements in areas where they operate, any costs incurred to repair, damage, or pay liabilities would adversely affect the Corporation's financial position, including the amount of funds that may be available for development programs, debt repayments, or dividend payments to shareholders.

In addition, the Corporation's unconventional oil and gas operations (such as the development and production of Bakken oil and shale gas) involve certain additional risks and uncertainties. The drilling and completion of wells and operations on these unconventional assets 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 able 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 may also be more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore. In addition, the fracturing activities required to be undertaken on these unconventional assets may be more extensive and complicated than fracturing the geological formations in the Corporation's other areas of operation and require greater volumes of water than conventional wells. The management of water and the treatment of produced water from these wells may be more costly than the management of produced water from other geologic formations.

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

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

Dividends on the Corporation's Common Shares are variable.

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

To the extent that the Corporation uses internally-generated cash flow to finance acquisitions, development costs and other significant capital expenditures, the amount of cash available to pay dividends to the Corporation's shareholders may be reduced. To the extent that external sources of capital, including debt or the issuance of additional Common Shares or other securities of the Corporation, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain, develop or expand its oil and gas reserves and resources and to invest in assets, 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 to its shareholders. In addition, variations in interest rates and scheduled principal repayments, if and as required under the terms of the Credit Facilities, could result in significant changes in the amount required to be applied to debt service. Certain covenants in agreements with lenders may also limit payments of dividends.

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

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

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

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

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

Circumstances may arise where directors and officers of the Corporation are directors or officers of corporations or other entities involved in the oil and gas industry which are in competition to the interests of the Corporation. See "*Directors and Officers – Conflicts of Interest*".

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, a breach of privacy laws, and 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 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 of U.S. courts of liabilities based solely upon the U.S. federal securities laws or the securities laws of any state within the United States.

Market for Securities

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

The following table sets forth certain trading information for the Common Shares on the TSX composite index and the United States composite index information for 2016.

	TSX Composite Trading			U.S. Composite Trading		
Month	**High**	**Low**	**Volume**	**High**	**Low**	**Volume**
January	5.08	2.68	60,802,023	3.66	1.84	33,811,983
February	4.58	3.37	46,266,821	3.35	2.43	28,199,613
March	5.37	3.82	57,919,116	4.03	2.84	43,291,417
April	7.12	4.68	54,614,431	5.70	3.55	34,928,872
May	7.43	6.04	82,342,803	5.74	4.69	36,118,141
June	8.78	6.89	66,975,757	6.94	5.27	31,844,783
July	8.79	7.46	44,929,682	6.74	5.67	19,383,211
August	10.06	7.51	45,094,921	7.82	5.62	21,652,268
September	9.45	7.43	52,989,510	7.36	5.61	23,054,437
October	10.12	8.24	73,641,986	7.74	6.28	25,644,646
November	11.86	8.50	55,900,180	8.84	6.26	26,040,442
December	13.55	11.47	46,765,526	10.33	8.65	26,445,809

Directors and Officers

DIRECTORS OF THE CORPORATION

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

Name and Residence	Director Since	Principal Occupation for Past Five Years
Elliott Pew(1) Boerne, Texas, United States	September 2010	Director of Southwestern Energy Company, a NYSE-listed oil and gas company, since July 2012. Prior thereto, a director of Common Resources III, L.L.C., a private oil and gas company, since May 2012, and a director of Common Resources II, L.L.C., a private oil and gas company, from May 2010 to August 2012.
David H. Barr(4)(6) The Woodlands, Texas, United States	July 2011	Corporate director. Prior thereto, director, President, and Chief Executive Officer and, prior thereto, the Chairman of the board of directors of Logan International Inc., a TSX-listed oil and gas services company focused on downhole tools and completion services. Director of ION Geophysical Corporation, a NYSE-listed oil and gas seismic company. Prior thereto, Group President of various divisions of Baker Hughes Incorporated, a NYSE-listed oilfield services company.
Michael R. Culbert(2)(3)(4) Calgary, Alberta, Canada	March 2014	Mr. Culbert is Vice Chairman of Progress Energy Canada Ltd. ("**Progress Energy**"), an oil and gas company, since November 2016. He continues to serve as a director on the boards of Progress Energy and Pacific Northwest LNG, each an oil and gas company. Prior thereto, he was President and Chief Executive Officer of Progress Energy.
Ian C. Dundas Calgary, Alberta, Canada	July 2013	President & Chief Executive Officer of Enerplus since July 2013. Prior thereto, Executive Vice President and Chief Operating Officer of Enerplus from April 2011 to July 2013 and prior thereto, Senior Vice President, Business Development of Enerplus from August 2010.
Hilary A. Foulkes(2)(4)(5)(6)(8) Calgary, Alberta, Canada	February 2014	Corporate director. Currently Chair, Tudor, Pickering, Holt & Co. Securities – Canada, ULC. Prior thereto, Executive Vice President and Chief Operating Officer of Penn West Petroleum Ltd., a TSX and NYSE-listed oil and gas company, from 2011 to 2012.
Robert B. Hodgins(2)(3)(7) Calgary, Alberta, Canada	November 2007	Corporate director and independent businessman.
Susan M. MacKenzie(4)(5)(6) Calgary, Alberta, Canada	July 2011	Corporate director. Prior thereto, independent consultant from 2010 to 2015.
Glen D. Roane(2)(3) Canmore, Alberta, Canada	June 2004	Corporate director.
Sheldon B. Steeves(2)(5) Calgary, Alberta, Canada	June 2012	Corporate director. From January 2001 until April 2012, Chairman and Chief Executive Officer of Echoex Ltd., a junior private oil and gas company.

Notes:
(1) Chairman of the board of directors and ex officio member of all committees of the board of directors.
(2) The Audit & Risk Management Committee is currently comprised of Robert B. Hodgins as Chair, Michael R. Culbert, Hilary A. Foulkes, Glen D. Roane and Sheldon B. Steeves.
(3) The Corporate Governance & Nominating Committee is currently comprised of Glen D. Roane as Chair, Michael R. Culbert and Robert B. Hodgins.
(4) The Compensation & Human Resources Committee is currently comprised of Susan M. MacKenzie as Chair, David H. Barr, Michael R. Culbert and Hilary A. Foulkes.
(5) The Reserves Committee is currently comprised of Sheldon B. Steeves as Chair, Susan M. MacKenzie and Hilary A. Foulkes.
(6) The Safety & Social Responsibility Committee is currently comprised of David H. Barr as Chair, Hilary A. Foulkes and Susan M. MacKenzie.

(7) Mr. Hodgins was a director of Skope Energy Inc. ("**Skope**") in November 2012 when Skope entered into a settlement agreement with Pine Cliff Energy Ltd. ("**Pine Cliff**") and filed for protection under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**"). A plan for compromise and arrangement under the CCAA filed by Pine Cliff and Skope was accepted by the Court of Queen's Bench of Alberta on January 15, 2013, received the requisite approval of Skope's creditors on February 15, 2013 and came into effect on February 20, 2013. Mr. Hodgins resigned as a director of Skope on February 19, 2013.

(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. On March 3, 2016, Parallel filed an assignment in bankruptcy and CCAA were terminated.

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 Enerplus since July 2013. Prior thereto, Executive Vice President and Chief Operating Officer of Enerplus from April 2011 to July 2013 and prior thereto, Senior Vice President, Business Development of Enerplus from August 2010.
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. Vice President, Finance of the Corporation since July 2013. Prior thereto, Controller, and Senior Manager, Planning & Marketing.
Raymond J. Daniels Calgary, Alberta, Canada	Senior Vice President, Operations, People & Culture(1)	Senior Vice President, Operations, People & Culture of the Corporation since January 2017. Prior thereto, Senior Vice President, Operations of the Corporation since May 2012 and prior thereto, Senior Vice President, Canadian Operations of the Corporation since April 2011.
Eric G. Le Dain Calgary, Alberta, Canada	Senior Vice President, Corporate Development, Commercial	Senior Vice President, Corporate Development, Commercial of the Corporation since July 2013. Prior thereto, Senior Vice President, Strategic Planning, Reserves & Marketing of the Corporation since April 2011.
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 from April 2011 to September 2015.
Daniel J. Fitzgerald Calgary, Alberta, Canada	Vice President, Business Development	Vice President, Business Development of the Corporation since September 2015. From December 2012 to September 2015, Manager, Business Development & Strategic Planning. Prior thereto, Vice President, Corporate Development of Storm Resources Ltd. from September 2010 until November 2012.
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 Enerplus.
Edward L. McLaughlin Denver, Colorado, United States	President, U.S. Operations	President, U.S. Operations of the Corporation since May 2012. Prior thereto, Manager of Land of Enerplus USA since joining the Corporation in November 2011.
Shaina B. Morihira Calgary, Alberta, Canada	Corporate Controller	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 and Senior Financial Analyst of Progress Energy from April 2008 to December 2014.

(1) Ms. Lisa Ower resigned her duties as Vice President, People & Culture effective October 11, 2016. Mr. Raymond Daniels, Senior Vice President, Operations now has oversight of People & Culture.

COMMON SHARE OWNERSHIP

As of February 17, 2017, the directors and officers of the Corporation named above beneficially own, or control or exercise direction over, directly or indirectly, an aggregate of 723,853 Common Shares, representing approximately 0.3% of the outstanding Common Shares as of that date.

CONFLICTS OF INTEREST

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

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

AUDIT & RISK MANAGEMENT COMMITTEE DISCLOSURE

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

Legal Proceedings and Regulatory Actions

The Corporation is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Corporation's favour, the Corporation does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Corporation may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operations or liquidity. The Corporation is not and was not during 2016 a party to, and none of the Corporation's property is or was during 2016 the subject of, any legal proceeding that involves a claim for damages (exclusive of interest and costs) greater than 10% of its current assets as at December 31, 2016, and the Corporation has no knowledge of any such proceeding being contemplated.

Interest of Management and Others in Material Transactions

To the knowledge of the directors and executive officers of the Corporation, none of the directors or executive officers of the Corporation and no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of the Corporation's securities, nor any associate or affiliate of any of the foregoing, has had any material interest, direct or indirect, in any transaction with the Corporation since January 1, 2014 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 Security holders

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); and the Fifth Amending Agreement relating thereto (November 7, 2016);

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, as they were filed after the January 1, 2011 Conversion:

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.

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

Transfer Agent and Registrar

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

Additional Information

Additional information relating to the Corporation may be found on the Corporation's profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and on the Corporation's website at www.enerplus.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, as applicable, will be contained in the Corporation's information circular and proxy statement with respect to its 2017 annual meeting of shareholders. Furthermore, additional financial information relating to the Corporation is provided in the Corporation's audited consolidated financial statements and MD&A for the year ended December 31, 2016. 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 – 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 McDaniel's January 1, 2017 forecast prices. 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. McDaniel has audited the Corporation's internal evaluation of these properties.

The following sections and tables summarize, as at December 31, 2016, 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 price forecast supplied by McDaniel as of January 1, 2017, and 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 waterflood 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 McDaniel's January 1, 2017 forecast prices.

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, 2016, 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, 2016

PROJECT MATURITY SUB-CLASS	CONTINGENT RESOURCES													
	Light & Medium Oil		Heavy Oil		Tight Oil		Natural Gas Liquids		Conventional Natural Gas		Shale Gas		Total	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MBOE)	Net (MBOE)
Development Pending	3,812	3,191	25,633	21,464	89,287	71,340	10,098	8,069	1,012	877	720,073	576,012	249,011	200,213

Risked Net Present Value of Future Net Revenue
Contingent Resources (Forecast Prices and Costs)
As of December 31, 2016

	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	4,656.1	1,976.6	901.3	411.8	169.6

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 34.4 MMBOE (29.6 MMBOE risked) being classified as economic contingent resources effective as of December 31, 2016. The unrisked net present value of future net revenue, discounted at 10%, of these contingent resources is $333.3 million ($290.6 million risked). This internal evaluation has been independently audited by McDaniel. Improved oil recovery from five existing waterfloods through optimization work accounts for approximately 12.5 MMBOE of the total volumes; 7.7 MMBOE from areas producing heavy crude oil and 4.8 MMBOE from areas producing light or medium crude oil. Approximately 21.9 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 $759.2 million of capital will be required. For the improved oil recovery projects this capital will be spent from 2017 to 2025, and from 2017 to 2038 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 90% for the 20.7 MMBOE of contingent resources assigned to the Medicine Hat Glauconitic "C" East Unit. This estimate is based on the success of the initial pilot projects and the Corporation's approval to expand the current projects. For the remaining waterflood contingent resources, a chance of development of 80% is estimated 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.

Canadian Natural Gas Properties

The Corporation had disclosed Development Pending Contingent Resources for the Wilrich property in 2015. This property was divested in 2016.

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 119.8 MMBOE (107.8 MMBOE risked) of economic contingent resources attributable to these formations, effective as of December 31, 2016, an increase of approximately 24% from the estimate as of December 31, 2015 notwithstanding the divestment of an estimated 7.3 MMBOE of contingent resources in non-operated lands at Fort Berthold. The increase was primarily the result of the Corporation's decision to drill currently spaced units to higher densities as compared to December 31, 2015. 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 215.3 net future drilling locations over and above 88.5 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$2,195.0 million (or CDN$2,588.5 million) between 2020 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 561 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 is $361.9 million. The Corporation has approximately 125.8 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 consists of lack of corporate approval for development in addition to 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. A significant factor related to the estimate is the limited long-term performance history in the immediate area of the contingent resources. There are a number of inherent risks and contingencies associated with the development of the interests in the property including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on industry partners in project development, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in 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 837 Bcf (669.6 Bcf risked) at December 31, 2016. The unrisked NPV associated with these contingent resources is $311.0 million ($248.8 million risked). Approximately 53.6 Bcf of contingent resources were reclassified as reserves in 2016. The Corporation saw an increase in the contingent resources estimate assigned to its non-operated leases in northeast Pennsylvania due to continued development which held the lands that were previously at risk of expiry. The remaining contingent resources are economic based on the forecast price and cost assumptions used for the Corporation's year-end 2016 reserves evaluations. This estimate represents a non-reserve land utilization rate of 95% and average well ultimate recovery of approximately 8.7 Bcf. These contingent resources are classified into "development pending" project maturity sub-class as it is anticipated that 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$622.4 million (or CDN$732.2 million) of capital will be required to develop these contingent resources with multifractured horizontal wells and development will occur from 2020 to 2028. 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, 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.

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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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, 2016, 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, 2016, 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	Audited	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (in $ thousands) Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	December 31, 2016	Canada	-	$ 425,283.2	$ 454,340.4	$ 879,623.7
McDaniel & Associates Consultants Ltd.	December 31, 2016	North Dakota & Montana, USA	-	US$1,485,770.0 (1)	-	US$1,485,770.0 (1)
Netherland, Sewell & Associates, Inc.	December 31, 2016	Pennsylvania, USA	-	US$593,022.0 (1)	-	US$593,022.0 (1)
TOTALS				$ 2,909,219.3	$ 454,340.4	$ 3,363,559.8

(1) Future net revenue in $US was converted to $Cdn using McDaniel's forecast of exchange rates. These are 0.75 for 2017, 0.775 for 2018, 0.80 for 2019, 0.825 for 2020 and 0.85 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, 2016	Canada	29.6	$ 290,616.6	-	$ 290,616.6
Development Pending Contingent Resources (2C)	McDaniel & Associates Consultants Ltd.	December 31, 2016	North Dakota, USA	107.8	US$309,891.3	-	US$309,891.3
Development Pending Contingent Resources (2C)	Netherland, Sewell & Associates, Inc.	December 31, 2016	Pennsylvania, USA	111.6	-	US$211,887.1	US$211,887.1

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

Calgary, Alberta, Canada

February 21, 2017

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, 2017

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

"*Eric G. Le Dain*"

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

"*Elliott Pew*"
Elliott Pew
Director

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

February 24, 2017

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

A. THE AUDIT & RISK MANAGEMENT COMMITTEE'S CHARTER

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

B. COMPOSITION OF THE AUDIT & RISK MANAGEMENT COMMITTEE

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

C. RELEVANT EDUCATION AND EXPERIENCE

Name (Director Since)	Principal Occupation and Biography
Robert B. Hodgins (Honors B.A. (Business), 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 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)	Mr. Culbert is Vice Chairman of Progress Energy Canada Ltd. ("**Progress Energy**"), an oil and gas company, since November 2016. He continues to serve as a director on the boards of Progress Energy and Pacific Northwest LNG, each an oil and gas company. Prior thereto, he was President and Chief Executive Officer of Progress Energy.
Hilary A. Foulkes (B.Sc., Honours (Earth Sciences)) (Director since February 2014)	Ms. Foulkes has over 30 years of oil and gas industry experience and is currently Chair, Tudor, Pickering, Holt & Co. Securities – Canada, ULC. From 2008 to 2012, Ms. Foulkes held a number of executive roles at Penn West Petroleum Ltd., a TSX and NYSE-listed oil and gas company, including Executive Vice President and Chief Operating Officer. Prior thereto, Ms. Foulkes was Managing Director at Scotia Waterous, an investment banking firm, from April 2000 to March 2008. Ms. Foulkes holds an Honours Bachelor of Science degree in Earth Sciences from the University of Waterloo, is a professional geologist, and a member of the Association of Professional Engineers and Geoscientists of Alberta and Canadian Association of Petroleum Geologists.

Name (Director Since)	Principal Occupation and Biography
Glen D. Roane (B.A., MBA) (Director since June 2004) Other Public Directorships • Badger Daylighting Ltd. (provider of non-destructive excavation services) • 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.
Sheldon B. Steeves (B.Sc. (Geology)) (Director since June 2012) Other Public Directorships • NuVista Energy Ltd. (oil and gas exploration and production company) • PrairieSky Royalty Ltd. (oil and gas royalty-focused company)	Mr. Steeves has over 38 years of experience in the North American oil and gas industry and is currently a director of NuVista Energy Ltd., a TSX-listed Canadian oil and gas company with operations in the Western Canadian Sedimentary Basin, and of PrairieSky Royalty Ltd., a TSX-listed Canadian oil and gas royalty-focused company. From January 2001 until April 2012, Mr. Steeves was Chairman and Chief Executive Officer of Echoex Ltd., a junior oil and gas private company focused on greenfield organic growth in Western Canada. Mr. Steeves spent over 15 years at Renaissance Energy Ltd., where he was appointed Chief Operating Officer in 1997. Mr. Steeves holds a Bachelor of Science in Geology from the University of Calgary.

D. PRE-APPROVAL POLICIES AND PROCEDURES

The Committee has implemented a policy restricting the services that may be provided by the Corporation's auditors and the fees paid to the Corporation's auditors. Prior to the engagement of the Corporation's auditors to perform both audit and non-audit services, the Committee pre-approves the provision of the services. In making their determination regarding non-audit services, the Committee considers the compliance with the policy and the provision of non-audit services in the context of avoiding impact on auditor independence. All audit and non-audit fees paid to Deloitte in 2016 and 2015 were pre-approved by the Committee. Based on the Committee's discussions with management and the independent auditors, the Committee is of the view that the provision of the non-audit services by Deloitte described above is compatible with maintaining that firm's independence from the Corporation.

E. EXTERNAL AUDITOR SERVICE FEES

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

	2016	2015
	(in $ thousands)	
Audit fees(1)	$ 654.7	$ 773.3
Audit-related fees(2)	-	-
Tax fees(3)	43.9	129.2
All other fees(4)	-	-
	$ 698.6	$ 902.6

Notes:

(1) Audit fees were for professional services rendered by Deloitte 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 reasonably related to the performance of the audit or review of the Corporation's financial statements and not reported under "Audit fees" above.

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

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

AUDIT & RISK MANAGEMENT COMMITTEE CHARTER

I. AUTHORITY

The Audit & Risk Management Committee (the "Committee") of the Board of Directors (the "Board") of Enerplus Corporation (the "Corporation") shall be comprised of three or more Directors as determined from time to time by resolution of the Board. Consistent with the appointment of other Board committees, the members of the Committee shall be elected by the Board at the first meeting of the Board following each annual meeting of Shareholders of the Corporation or at such other time as may be determined by the Board. The 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 US 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 risk assessment and the policies to monitor, mitigate and report such business risks.

Other Matters

18. Review of appointment or dismissal of senior financial executives;

19. Conduct or authorize investigations into any matters within the Committee's scope of responsibilities, including retaining outside counsel or other consultants or experts for this purpose;

20. Review the disclosure made in the Annual 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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Exhibit 99.2

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2016, our internal control over financial reporting is effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2016, has been audited by Deloitte LLP, the Independent Registered Public Accounting Firm, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2016.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 24, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the internal control over financial reporting of Enerplus Corporation and subsidiaries (the “Company”) as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and our report dated February 24, 2017 expressed an unmodified/unqualified opinion on those financial statements.

/s/ “Deloitte LLP”

Chartered Professional Accountants

February 24, 2017
Calgary, Canada

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 23, 2017. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by Deloitte LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. The Report of Independent Registered Public Accounting Firm outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accounting Firm and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 24, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the accompanying consolidated financial statements of Enerplus Corporation and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2016, and December 31, 2015, and the consolidated statements of income/(loss) and comprehensive income/(loss), consolidated statements of changes in shareholders' equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2016, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enerplus Corporation and subsidiaries as at December 31, 2016, and December 31, 2015, and their financial performance and their cash flows for each of the years in the three-year period ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ "Deloitte LLP"

Chartered Professional Accountants

February 24, 2017
Calgary, Canada

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2016	December 31, 2015
Assets			
Current assets			
Cash		$ 1,257	$ 7,498
Restricted cash	2(f)	392,048	—
Accounts receivable	3	115,368	132,156
Derivative financial assets	15	—	71,438
Other current assets		6,721	9,953
		515,394	221,045
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	726,452	1,166,587
Other capital assets, net	4	11,978	19,686
Property, plant and equipment		738,430	1,186,273
Goodwill	2(g)	651,663	657,831
Deferred income tax asset	13	733,363	516,085
Total Assets		$ 2,638,850	$ 2,581,234
Liabilities			
Current liabilities			
Accounts payable	6	$ 184,534	$ 239,950
Dividends payable		2,405	6,196
Current portion of long-term debt	7	29,539	—
Derivative financial liabilities	15	28,615	4,100
		245,093	250,246
Derivative financial liabilities	15	12,266	3,193
Long-term debt	7	739,286	1,223,682
Asset retirement obligation	8	181,700	206,359
		933,252	1,433,234
Total Liabilities		1,178,345	1,683,480
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2016 - 240 million shares			
December 31, 2015 - 206 million shares	14	3,365,962	3,133,524
Paid-in capital		73,783	56,176
Accumulated deficit		(2,332,641)	(2,694,618)
Accumulated other comprehensive income/(loss)		353,401	402,672
		1,460,505	897,754
Total Liabilities & Shareholders' Equity		$ 2,638,850	$ 2,581,234
Commitments, Contingencies and Guarantees	16		

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Approved on behalf of the Board of Directors:

/s/ Elliott Pew
Director

/s/ Robert B. Hodgins
Director

Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss)

For the year ended December 31 (CDN$ thousands)	Note	2016	2015	2014
Revenues				
Oil and natural gas sales, net of royalties	9	$ 722,732	$ 884,392	$ 1,526,194
Commodity derivative instruments gain/(loss)	15	(29,397)	142,724	234,373
		693,335	1,027,116	1,760,567
Expenses				
Operating		247,917	340,483	348,596
Transportation		107,147	114,691	101,183
Production taxes		37,417	50,899	81,522
General and administrative	10	86,319	103,870	105,041
Depletion, depreciation and accretion		328,964	508,179	567,642
Asset impairment	5	301,171	1,352,428	—
Interest	11	45,443	66,456	62,820
Foreign exchange (gain)/loss	12	(40,526)	173,933	57,090
Gain on divestment of assets	4	(559,235)	—	—
Gain on prepayment of senior notes	7	(19,270)	—	—
Other expense /(income)		(2,230)	7,055	(231)
		533,117	2,717,994	1,323,663
Income/(Loss) Before Taxes		160,218	(1,690,878)	436,904
Current income tax expense/(recovery)	13	(2,351)	(16,887)	4,998
Deferred income tax expense/(recovery)	13	(234,847)	(150,588)	132,830
Net Income/(Loss)		$ 397,416	$ (1,523,403)	$ 299,076
Other Comprehensive Income/(Loss)				
Change in cumulative translation adjustment		(49,271)	307,194	143,817
Changes due to marketable securities (net of tax)				
Unrealized gain/(loss)		—	—	(145)
Realized (gain)/loss reclassified to net income		—	—	2,503
Other Comprehensive Income/(Loss)		(49,271)	307,194	146,175
Total Comprehensive Income/(Loss)		$ 348,145	$ (1,216,209)	$ 445,251
Net Income/(Loss) per Share				
Basic	14	$ 1.75	$ (7.39)	$ 1.46
Diluted	14	$ 1.72	$ (7.39)	$ 1.44

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	**2016**	**2015**	**2014**
Share Capital			
Balance, beginning of year	$ 3,133,524	$ 3,120,002	$ 3,061,839
Public offering (net of issue costs)	223,031	—	—
Share-based compensation – settled	9,407	10,050	—
Stock Option Plan – cash	—	3,205	31,350
Stock Option Plan – exercised	—	267	4,978
Stock Dividend Plan	—	—	21,835
Balance, end of year	$ 3,365,962	$ 3,133,524	$ 3,120,002
Paid-in Capital			
Balance, beginning of year	$ 56,176	$ 46,906	$ 38,398
Share-based compensation – settled	(9,407)	(10,050)	—
Share-based compensation – non-cash	27,014	19,587	13,486
Stock Option Plan – exercised	—	(267)	(4,978)
Balance, end of year	$ 73,783	$ 56,176	$ 46,906
Accumulated Deficit			
Balance, beginning of year	$ (2,694,618)	$ (1,039,260)	$ (1,117,238)
Net income/(loss)	397,416	(1,523,403)	299,076
Dividends	(35,439)	(131,955)	(221,098)
Balance, end of year	$ (2,332,641)	$ (2,694,618)	$ (1,039,260)
Accumulated Other Comprehensive Income/(Loss)			
Balance, beginning of year	$ 402,672	$ 95,478	$ (50,697)
Change in cumulative translation adjustment	(49,271)	307,194	143,817
Changes due to marketable securities (net of tax)			
Unrealized gain/(loss)	—	—	(145)
Realized (gain)/loss reclassified to net income	—	—	2,503
Balance, end of year	$ 353,401	$ 402,672	$ 95,478
Total Shareholders' Equity	$ 1,460,505	$ 897,754	$ 2,223,126

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	**Note**	**2016**	**2015**	**2014**
Operating Activities				
Net income/(loss)		$ 397,416	$ (1,523,403)	$ 299,076
Non-cash items add/(deduct):				
Depletion, depreciation and accretion		328,964	508,179	567,642
Asset impairment	5	301,171	1,352,428	—
Changes in fair value of derivative instruments	15	105,026	169,336	(242,038)
Deferred income tax expense/(recovery)	13	(234,847)	(150,588)	132,830
Foreign exchange (gain)/loss on debt and working capital	12	(40,634)	160,791	68,202
Share-based compensation	14	27,014	19,587	13,486
Gain on the divestment of assets	4	(559,235)	—	2,798
Gain on prepayment of senior notes	7	(19,270)	—	—
Derivative settlement of foreign exchange swaps	7	—	(43,229)	17,024
Asset retirement obligation expenditures	8	(8,390)	(14,935)	(19,409)
Changes in non-cash operating working capital	18	15,075	(12,830)	(52,414)
Cash flow from operating activities		312,290	465,336	787,197
Financing Activities				
Proceeds from the issuance of shares (net of issue costs)	14	220,410	3,205	31,350
Cash dividends	14	(35,439)	(131,955)	(199,263)
Increase/(decrease) in bank credit facility		(55,999)	6,626	(136,918)
Proceeds/(repayment) of senior notes	7	(335,400)	(103,198)	167,497
Derivative settlement on senior notes	7	—	43,229	(17,024)
Changes in non-cash financing working capital		(3,791)	(12,320)	263
Cash flow from/(used in) financing activities		(210,219)	(194,413)	(154,095)
Investing Activities				
Capital and office expenditures		(210,611)	(497,875)	(817,968)
Property and land acquisitions		(126,126)	(9,552)	(18,491)
Property divestments	4	670,364	286,614	203,576
Increase in restricted cash		(392,048)	—	—
Sale of marketable securities		—	—	13,300
Changes in non-cash investing working capital		(49,472)	(47,586)	(17,449)
Cash flow from/(used in) investing activities		(107,893)	(268,399)	(637,032)
Effect of exchange rate changes on cash		(419)	2,938	2,976
Change in cash		(6,241)	5,462	(954)
Cash, beginning of year		7,498	2,036	2,990
Cash, end of year		$ 1,257	$ 7,498	$ 2,036

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Notes to Consolidated Financial Statements

1) REPORTING ENTITY

These annual audited Consolidated Financial Statements ("Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation (the "Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada. The Consolidated Financial Statements were authorized for issue by the Board of Directors on February 23, 2017.

2) SIGNIFICANT ACCOUNTING POLICIES

The following significant accounting policies are presented to assist the reader in evaluating these Consolidated Financial Statements and, together with the following notes, are an integral part of the Consolidated Financial Statements.

a) Basis of Preparation

Enerplus' Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). These Consolidated Financial Statements present Enerplus' financial position as at December 31, 2016 and 2015 and results of operations for the years ended December 31, 2016, and the 2015 and 2014 comparative years. Certain prior period amounts have been restated to conform with current period presentation.

i. Reporting Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus' reporting currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

ii. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment, asset retirement obligations, income taxes, income tax asset values, impairment assessments of goodwill and the fair value of derivative instruments. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions. In the opinion of management, these Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

iii. Basis of Consolidation

These Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled oil and natural gas assets are accounted for following the concept of undivided interest, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

The acquisition method of accounting is used to account for acquisitions of companies that meet the definition of a business under U.S. GAAP. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date.

b) Revenue

Revenue associated with the sale of oil and natural gas is recognized when title passes from the Company to its customers if collectability is reasonably certain and the sales price is determinable. Revenue is measured at the fair value of the consideration received or receivable based on price, volumes delivered and contractual delivery points. Realized gains and losses from commodity price risk management activities are recognized in revenue when the contract is settled. Unrealized gains and losses on commodity price risk management activities are recognized in revenue based on the changes in fair value of the contracts at the end of the respective reporting period.

c) Transportation

Enerplus generally sells oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a net-back arrangement, under which the Company sells crude oil or natural gas at the wellhead and collects a price, net of the transportation incurred by the purchaser. In this case, sales are recorded at the price received from the purchaser, net of transportation costs.

Under the other arrangement, Enerplus sells crude oil or natural gas at a specific delivery point, pays transportation to a third party and receives proceeds from the purchaser with no transportation deduction. In this case transportation costs are recorded as transportation expense on the Consolidated Statements of Income/(Loss). Due to these two distinct selling arrangements, Enerplus' computed realized prices, before the impact of derivative instruments, include revenues which are reported under two separate bases.

d) Oil and Natural Gas Properties

Enerplus uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs incurred in finding oil and natural gas reserves are capitalized, including general and administrative costs directly attributable to these activities. These costs are recorded on a country-by-country cost centre basis as oil and natural gas properties subject to depletion ("full cost pool"). Costs associated with production and general corporate activities are expensed as incurred.

The net carrying value of both proved and unproved oil and natural gas properties is depleted using the unit of production method using proved reserves, as determined using a constant price assumption of the simple average of the preceding twelve months' first-day-of-the-month commodity prices ("SEC prices"). The depletion calculation takes into account estimated future development costs necessary to bring those reserves into production.

Under full cost accounting, a ceiling test is performed on a cost centre basis. Enerplus limits capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and deferred income tax liabilities, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties ("the ceiling"). If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher oil and natural gas prices subsequently increase the ceiling.

Under full cost accounting rules, divestitures of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would have otherwise significantly altered the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized.

e) Other Capital Assets

Other capital assets are recorded at historical cost, net of depreciation, and include furniture, fixtures, leasehold improvements and computer equipment. Depreciation is calculated on a straight-line basis over the estimated useful life of the respective asset. The cost of repairs and maintenance is expensed as incurred.

f) Restricted Cash

Restricted cash on the Consolidated Balance Sheets as of December 31, 2016 consists of proceeds from the sale of our non-operated North Dakota properties. The funds have been deposited with a qualified intermediary through two financial institutions and which is restricted for application towards future acquisitions to facilitate a potential like-kind exchange transaction for U.S. federal income tax purposes. The funds continue to be held in escrow and will remain there for a period of up to 180 days from the closing date of the sale. Counterparty credit risk related to this restricted cash is managed through the use of a qualified trust account, whereby the assets held in trust must be segregated from the financial institution's assets, and in the event of its bankruptcy, the funds would not be subject to payments to the creditors of the financial institution.

g) Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The portion of goodwill that relates to U.S. operations fluctuates due to changes in foreign exchange rates. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Impairment testing is performed on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus performs a qualitative assessment by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). For the purposes of goodwill impairment testing, Enerplus has one consolidated reporting unit.

During the 2016 and 2015 years there were no additions or impairments to goodwill.

h) Asset Retirement Obligations

Enerplus' oil and natural gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future asset retirement obligation liability at each balance sheet date. The associated asset retirement cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability and related asset retirement cost can arise as a result of revisions in the estimated amount or timing of cash flows.

Depletion of asset retirement costs and increases in asset retirement obligations resulting from the passage of time are recorded to depreciation, depletion and accretion and charged against net income in the Consolidated Statements of Income/(Loss).

i) Income Tax

Enerplus uses the liability method of accounting for income taxes. Deferred income tax assets and liabilities are recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax assets are reviewed each period and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized. Enerplus considers both positive and negative evidence including historic and expected future taxable income, reversing existing temporary differences and tax basis carry forward periods in making this assessment. A valuation allowance is removed in any period where available evidence indicates all or a portion of the valuation allowance is no longer required. The financial statement effect of an uncertain tax position is recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. Penalties and interest related to income tax are recognized in income tax expense.

j) Financial Instruments

i. Fair Value Measurements

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. For financial instruments carried at fair value, inputs used in determining the fair value are characterized according to the following fair value hierarchy:

- Level 1 – Inputs represent quoted market prices in active markets for identical assets or liabilities.
- Level 2 – Inputs other than quoted market prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted market prices for similar assets or liabilities in active markets or other market corroborated inputs.
- Level 3 – Inputs that are not observable from objective sources, such as forward prices supported by little or no market activity or internally developed estimates of future cash flows used in a present value model.

Subsequent measurement is based on classification of the financial instrument into one of the following five categories: held-for-trading, held-to-maturity, available-for-sale, loans and receivables or other financial liabilities.

ii. Non-derivative financial instruments

From time-to-time, Enerplus may hold certain marketable securities in entities involved in the oil and gas industry which would be included in other assets on the Consolidated Balance Sheets. These investments may include both publicly traded and unlisted marketable securities. Publicly traded investments are classified as available-for-sale and carried at fair value based on a Level 1 designation, with changes in fair value recorded in other comprehensive income. Fair values are determined by reference to quoted market bid prices at the close of business on the balance sheet date. When investments are ultimately sold any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed.

The carrying amount of cash, restricted cash, accounts receivable, accounts payable, dividends payable and bank credit facilities reported on the Consolidated Balance Sheets approximates fair value. The fair value of long-term debt has been disclosed in Note 15.

Enerplus capitalizes debt issuance costs, except for those related to revolving credit facilities. These costs are presented on the Consolidated Balance Sheets as a direct deduction from the carrying amount of the related debt liability.

iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

Enerplus' crude oil, natural gas and natural gas liquids physical delivery purchase and sales contracts qualify as normal purchases and sales as they are entered into and held for the purpose of receipt or delivery of products in accordance with the Company's expected purchase, sale or usage requirements. As such, these contracts are not considered derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

k) Foreign Currency

i. Foreign currency transactions

Transactions denominated in foreign currencies are translated to Canadian dollars using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

ii. Foreign operations

Assets and liabilities of Enerplus' U.S. operations are translated into Canadian dollars at period end exchange rates while revenues and expenses are translated using average rates for the period. Gains and losses from the translation are deferred and included in the cumulative translation adjustment which is recorded in accumulated other comprehensive income.

l) Share-Based Compensation

Enerplus' share-based compensation plans include its cash-settled Restricted Share Unit ("RSU"), Performance Share Unit ("PSU") and Director Share Unit ("DSU") plans, its equity-settled RSU and PSU plans, as well as Enerplus' Stock Option Plan. The final cash-settled RSU grant was paid in 2016. The Company is authorized to issue up to 5% of outstanding common shares from treasury in relation to its equity-settled RSU and PSU plans. In 2014, the Company suspended the issuance of stock options.

i. RSU, PSU, and DSU plans

Under Enerplus' RSU plan, employees receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

Under Enerplus' PSU plan, executives and management receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. The value upon vesting is based on value of the underlying shares plus notional accrued dividends along with a multiplier that ranges from 0 to 2 depending on Enerplus' performance compared to the TSX oil and gas index over the vesting period.

Under Enerplus' DSU plan, directors receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual retainer value and they vest upon the director leaving the Board. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period. All DSU grants are settled in cash.

Enerplus recognizes a liability in respect of its cash-settled long-term incentive plans based on their estimated fair value. The liability is re-measured at each reporting date and at settlement date with any changes in the fair value recorded as share-based compensation, included in general and administrative expense.

Enerplus recognizes non-cash share-based compensation expense over the vesting period of the equity-settled long-term incentive plans, based on the estimated grant date fair value of the respective awards. Share-based compensation charges are recorded on the Consolidated Statements of Income/(Loss) with an offset to paid-in capital. Each period, management performs an estimate of the PSU plan multiplier. Any differences that arise between the actual multiplier on plan settlement and management's estimate is recorded to share-based compensation. On settlement of these plans, amounts previously recorded to paid-in capital are reclassified to share capital.

ii. Stock options

Under Enerplus' Stock Option Plan, employees were granted options to purchase common shares of the Company at an exercise price equal to the market value of the common shares on the date the options are granted. Options granted were exercisable in thirds over the three year vesting schedule and expire seven years after the date the options are granted. Enerplus used the Black-Scholes option pricing model to calculate the grant date fair value of stock options granted under the Company's Stock Option Plan. This amount was charged to earnings as share-based compensation over the vesting period of the options, with a corresponding increase in paid-in capital. When options are exercised, the proceeds, together with the amount recorded in paid-in capital, are recorded to share capital.

m) Net Income Per Share

Basic net income per common share is computed by dividing net income by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from the exercise of all stock options would be used to repurchase common shares at the average market price.

n) Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recognized when it is probable that a liability has been incurred and the amount can be reasonably estimated. Contingencies are adjusted as additional information becomes available or circumstances change.

o) Accounting Changes and Recent Pronouncements Issued

i. Recently adopted accounting standards

Effective in 2016, Enerplus adopted the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"):

- ASU 2014-12, *Compensation – Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period*
- ASU 2015-02*, Amendments to the Consolidation Analysis*
- ASU 2015-03*, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*

The adoption of these ASUs did not have a material impact on Enerplus' Consolidated Financial Statements.

In January 2017, the FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the definition of a business.* The amendments in the ASU provide a screen to determine whether an integrated set of assets and activities (a "set") is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired is concentrated in a single or group of similar identifiable assets, that the set is not a business. The ASU is effective January 1, 2018 and is to be applied prospectively, with early adoption permitted. Enerplus has early adopted this ASU for the year ended December 31, 2016. As a result of the early adoption of this ASU, certain Canadian properties that were acquired during the year were accounted for as a property acquisition instead of a business combination.

ii. Future accounting changes

Enerplus will adopt the following ASU's issued by the FASB, which have been issued but are not yet effective.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers,* which will require entities to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard also will require expanded disclosures regarding the nature, amount, timing and certainty of revenue and cash flows from contracts with customers.

The FASB further issued several ASUs in 2016 which provide clarification on implementation of the amended standard, *Revenue from Contracts with Customers* (Topic 606), and included technical corrections and improvements and practical expedients that can be applied under certain circumstances. The amendments under these ASUs will become effective on January 1, 2018, however early adoption is permitted in 2017. Enerplus does not intend to early adopt these amendments, and continues to assess the impact they will have on the Consolidated Financial Statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* The ASU introduces a lessee accounting model that requires that most leases be recorded as a lease asset and lease liability on the balance sheet, with some exceptions. The ASU provides additional guidance on identifying and separating components of leases and a practical expedient on making this determination. The ASU is effective January 1, 2019, with early adoption permitted. Enerplus does not intend to early adopt these amendments, and continues to assess the impact they will have on the Consolidated Financial Statements.

In November 2016, the FASB issued ASU 2016-18, *Statements of Cash Flows – Restricted Cash*. The ASU requires amounts described as restricted cash and restricted cash equivalents to be included with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the Consolidated Statements of Cash Flows. The updated guidance is effective January 1, 2018, with early adoption permitted. The adoption of this update is not expected to have a material impact on the Consolidated Financial Statements.

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*. This standard eliminates Step 2 of the goodwill impairment test, and requires a goodwill impairment charge for the amount that the goodwill carrying amount exceeds the reporting unit's fair value. The updated guidance is effective for January 1, 2020, with early adoption permitted. Enerplus does not expect to early adopt these amendments, and continues to assess the impact they will have on the Consolidated Financial Statements.

3) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2016	December 31, 2015
Accrued receivables	$ 83,774	$ 91,378
Accounts receivable - trade	33,305	22,615
Current income tax receivable	1,564	21,410
Allowance for doubtful accounts	(3,275)	(3,247)
Total accounts receivable, net of allowance for doubtful accounts	$ 115,368	$ 132,156

4) PROPERTY, PLANT AND EQUIPMENT ("PP&E")

As at December 31, 2016 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,567,390	$ (12,840,938)	$ 726,452
Other capital assets	106,070	(94,092)	11,978
Total PP&E	$ 13,673,460	$ (12,935,030)	$ 738,430

As at December 31, 2015 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,541,670	$ (12,375,083)	$ 1,166,587
Other capital assets	105,124	(85,438)	19,686
Total PP&E	$ 13,646,794	$ (12,460,521)	$ 1,186,273

Acquisitions:

For the years ended December 31, 2016 and 2015, Enerplus acquired property and land totaling $126.1 million, and $9.6 million, respectively. For the year ended December 31, 2016, the acquisition of property and land consisted mainly of Enerplus' acquisition of assets in Ante Creek in NW Alberta for $110.3 million.

Divestments:

For the years ended December 31, 2016 and 2015, Enerplus disposed of properties for proceeds of $670.4 million and $286.6 million, respectively. Certain asset divestments in 2016 resulted in gains, as the divestments caused a significant alteration in the relationship between the cost centre's capitalized costs and proved reserves. During 2016, Enerplus recognized gains on asset divestments of $559.2 million. Enerplus did not recognize any gains on asset divestments in 2015.

5) IMPAIRMENT

a) Impairment of PP&E

($ thousands)	2016	2015	2014
Oil and natural gas properties:			
Canada cost centre	$ 89,359	$ 286,700	$ —
U.S. cost centre	211,812	1,065,728	—
Total impairment expense	$ 301,171	$ 1,352,428	$ —

The impairments for the period ended December 31, 2016 were due to lower 12-month average trailing crude oil and natural gas prices.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test as at December 31, 2016, 2015 and 2014:

Period	WTI Crude Oil US$/bbl	Exchange Rate US$/CDN	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
2016	$ 42.75	1.32	$ 52.26	$ 2.49	$ 2.17
2015	50.28	1.27	59.38	2.58	2.69
2014	94.99	1.09	94.84	4.30	4.60

b) Goodwill Impairment

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus' annual goodwill impairment assessment as at December 31, 2016 and December 31, 2015 indicated no impairment.

6) ACCOUNTS PAYABLE

($ thousands)	December 31, 2016	December 31, 2015
Accrued payables	$ 104,816	$ 167,253
Accounts payable - trade	79,718	72,697
Total accounts payable	$ 184,534	$ 239,950

7) DEBT

($ thousands)	December 31, 2016	December 31, 2015
Current:		
Senior notes	$ 29,539	$ —
	29,539	—
Long-term:		
Bank credit facility	$ 23,226	$ 86,543
Senior notes	716,060	1,137,139
	739,286	1,223,682
Total debt	$ 768,825	$ 1,223,682

Bank Credit Facility

Enerplus has a senior unsecured, covenant-based, $800 million bank credit facility that matures on October 31, 2019. Drawn fees range between 150 and 315 basis points over bankers' acceptance rates, with current drawn fees of 170 basis points. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility or repay the entire balance at the end of the term. At December 31, 2016 Enerplus had $23.2 million (December 31, 2015 - $86.5 million) drawn and was in compliance with all covenants under the facility. During 2016 a fee of $0.7 million (2015 - $0.3 million, 2014 - $0.6 million) was paid to extend the facility. The weighted average interest rate on the facility for the year ended December 31, 2016 was 2.6% (December 31, 2015 – 2.2%).

Senior Notes

During 2016 Enerplus repurchased US$267 million in outstanding senior notes at a discount, resulting in gains of $19.3 million. These repurchases resulted in total repayments of $335.4 million in 2016.

On June 18, 2015 Enerplus made bullet payments on both its US$40 million and $40 million senior notes, which were issued on June 18, 2009. On October 1, 2015 Enerplus made its fifth and final principal repayment of US$10.8 million on the US$54 million senior notes issued on October 1, 2003 and settled the corresponding foreign exchange swap. The final principal repayment totaled $11.0 million and a gain of $3.3 million was realized on the foreign exchange swap, which was recorded as a realized foreign exchange gain on the Consolidated Statements of Income/(Loss).

The terms and rates of the Company's outstanding senior notes are detailed below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)	CDN$ Carrying Value ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$ 140,923
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	26,854
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	400,125
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$110,000	147,697
					Total carrying value	$ 745,599
					Current portion	29,539
					Long-term portion	$ 716,060

At December 31, 2016 Enerplus was in full compliance with all covenants under the senior notes.

8) ASSET RETIREMENT OBLIGATION

At December 31, 2016 Enerplus estimated the present value of its asset retirement obligation to be $181.7 million (December 31, 2015 - $206.4 million) based on a total undiscounted liability of $452.1 million (December 31, 2015 - $556.4 million). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.86% at December 31, 2016 (December 31, 2015 – 5.91%). The majority of Enerplus' asset retirement obligation expenditures are expected to be incurred between 2025 and 2055.

($ thousands)	December 31, 2016	December 31, 2015
Balance, beginning of year	$ 206,359	$ 288,692
Change in estimates	5,496	(35,386)
Property acquisition and development activity	3,003	761
Divestments	(35,635)	(48,748)
Settlements	(8,390)	(14,935)
Accretion expense	10,867	15,975
Balance, end of year	$ 181,700	$ 206,359

9) OIL AND NATURAL GAS SALES

($ thousands)	2016	2015	2014
Oil and natural gas sales	$ 882,126	$ 1,052,382	$ 1,849,312
Royalties(1)	(159,394)	(167,990)	(323,118)
Oil and natural gas sales, net of royalties	$ 722,732	$ 884,392	$ 1,526,194

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Statements of Income/(Loss).

10) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	2016	2015	2014
General and administrative expense	$ 59,773	$ 81,312	$ 83,493
Share-based compensation expense	26,546	22,558	21,548
General and administrative expense	$ 86,319	$ 103,870	$ 105,041

11) INTEREST EXPENSE

($ thousands)	2016	2015	2014
Realized:			
Interest on bank debt and senior notes	$ 45,443	$ 66,456	$ 62,240
Unrealized:			
Cross currency interest rate swap (gain)/loss	—	—	580
Interest expense	$ 45,443	$ 66,456	$ 62,820

12) FOREIGN EXCHANGE

($ thousands)	2016	2015	2014
Realized:			
Foreign exchange (gain)/loss	$ 108	$ (8,705)	$ 11,165
Unrealized:			
Translation of U.S. dollar debt and working capital (gain)/loss	(40,634)	160,791	68,202
Cross currency interest rate swap (gain)/loss	—	—	(16,128)
Foreign exchange swap (gain)/loss	—	21,847	(6,149)
Foreign exchange (gain)/loss	$ (40,526)	$ 173,933	$ 57,090

13) INCOME TAXES

Enerplus' provision for income tax is as follows:

($ thousands)	2016	2015	2014
Current tax expense/(recovery)			
Canada	$ (661)	$ (795)	$ (543)
United States	(1,690)	(16,092)	5,541
Current tax expense/(recovery)	(2,351)	(16,887)	4,998
Deferred Tax expense/(recovery)			
Canada	$ (23,714)	$ (52,603)	$ 64,746
United States	(211,133)	(97,985)	68,084
Deferred tax expense/(recovery)	(234,847)	(150,588)	132,830
Income tax expense/(recovery)	$ (237,198)	$ (167,475)	$ 137,828

The following provides a reconciliation of income taxes calculated at the Canadian statutory rate to the actual income taxes:

($ thousands)	2016	2015	2014
Income/(loss) before taxes			
Canada	$ 121,257	$ (500,113)	$ 247,856
United States	38,961	(1,190,765)	189,048
Total income/(loss) before taxes	160,218	(1,690,878)	436,904
Canadian statutory rate	27.00%	27.00%	25.35%
Expected income tax expense/(recovery)	$ 43,259	$ (456,537)	$ 110,755
Impact on taxes resulting from:			
Change in valuation allowance	$ (266,896)	$ 443,655	$ 8,007
Foreign and statutory rate differences	(12,826)	(179,809)	11,204
Non-taxable capital (gains)/losses	(6,478)	23,450	8,318
Share-based compensation	6,611	4,395	2,636
Other	(868)	(2,629)	(3,092)
Income tax expense/(recovery)	$ (237,198)	$ (167,475)	$ 137,828

During 2015 the Alberta Provincial tax rate change resulted in an increase in the Canadian statutory rate by 1.65% for the year.

Deferred income tax asset (liability) consists of the following temporary differences:

As at December 31 ($ thousands)	2016	2015
Deferred income tax liabilities		
Derivative financial assets and credits	$ —	$ (17,319)
Total deferred income tax liabilities	—	(17,319)
Deferred income tax assets		
Property, plant and equipment	$ 257,105	$ 382,454
Tax loss carry-forwards and other credits	736,395	672,193
Asset retirement obligation	50,462	57,364
Derivative financial assets and credits	10,515	—
Other assets	26,753	36,156
Total deferred income tax assets	1,081,230	1,148,167
Less valuation allowance	(347,867)	(614,763)
Total deferred income tax assets, net	733,363	533,404
Net deferred income tax asset	$ 733,363	$ 516,085

In the current period, Enerplus reported a deferred income tax asset of $733.4 million (2015 - $516.1 million). We have a valuation allowance of $347.9 million at December 31, 2016 (2015 - $614.8 million).

Loss carry-forwards and tax credits available for tax reporting purposes:

As at December 31 ($ thousands)	2016	Expiration Date
Canada		
Capital losses	$ 1,224,000	Indefinite
Non-capital losses	377,000	2028-2036
United States		
Net operating losses	$ 894,000	2030-2036
Alternative minimum tax credits	112,000	Indefinite

Changes in the balance of Enerplus' unrecognized tax benefits are as follows:

($ thousands)	2016	2015	2014
Balance, beginning of year	$ 15,100	$ 17,000	$ 18,000
Increase/(decrease) for tax positions of prior years	—	(300)	2,700
Settlements	(1,800)	(1,600)	(3,700)
Balance, end of year	$ 13,300	$ 15,100	$ 17,000

If recognized, all of Enerplus' unrecognized tax benefits as at December 31, 2016 would affect Enerplus' effective income tax rate. It is not anticipated that the amount of unrecognized tax benefits will significantly change during the next 12 months.

A summary of the taxation years, by jurisdiction, that remain subject to examination by the taxation authorities are as follows:

Jurisdiction	Taxation Years
Canada - Federal & Provincial	2006-2016
United States - Federal & State	2008-2016

Enerplus and its subsidiaries file income tax returns primarily in Canada and the United States. Matters in dispute with the taxation authorities are ongoing and in various stages of completion.

14) SHAREHOLDERS' EQUITY

a) Share Capital

	2016		2015		2014	
Authorized unlimited number of common shares Issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	206,539	$ 3,133,524	205,732	$ 3,120,002	202,758	$ 3,061,839
Issued for cash:						
Public offering	33,350	230,115	—	—	—	—
Share issue costs (net of tax of $2,621)	—	(7,084)	—	—	—	—
Stock Option Plan	—	—	234	3,205	1,944	31,350
Non-cash:						
Share-based compensation - settled	594	9,407	573	10,050	—	—
Stock Option Plan - exercised	—	—	—	267	—	4,978
Stock Dividend Plan(1)	—	—	—	—	1,030	21,835
Balance, end of year	240,483	$ 3,365,962	206,539	$ 3,133,524	205,732	$ 3,120,002

(1) Effective with the October 2014 dividend, Enerplus suspended the Stock Dividend Plan.

The Company is authorized to issue an unlimited number of common shares without par value.

On May 31, 2016, Enerplus issued 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230,115,000 ($220,410,400, net of issue costs before tax).

At the Company's Annual General Meeting on May 6, 2016, the Shareholders of the Company approved a reduction in Enerplus' legal stated capital to $1 per share to be reflected in the contributed surplus account of the Company. This transaction does not result in an adjustment to the financial statements under U.S. GAAP.

b) Dividends

($ thousands)		2016		2015		2014
Cash dividends	$	35,439	$	131,955	$	199,263
Stock dividends[1]		—		—		21,835
Dividends to shareholders	$	35,439	$	131,955	$	221,098

(1) Effective with the October 2014 dividend, Enerplus suspended the Stock Dividend Plan.

For the year ended December 31, 2016 Enerplus paid dividends of $0.16 per weighted average common share totaling $35.4 million (December 31, 2015 - $0.64 per share and $132.0 million, December 31, 2014 - $1.08 per share and $221.1 million).

c) Share-based Compensation

The following table summarizes Enerplus' share-based compensation expense, which is included in General and Administrative expense on the Consolidated Statements of Income/(Loss):

($ thousands)		2016		2015		2014
Cash:						
Long-term incentive plans (recovery)/expense	$	3,114	$	874	$	(1,220)
Non-Cash:						
Long-term incentive plans expense		26,951		18,878		9,349
Stock option plan expense		63		709		4,137
Equity swap (gain)/loss		(3,582)		2,097		9,282
Share-based compensation expense	$	26,546	$	22,558	$	21,548

i) Long-term Incentive ("LTI") Plans

In 2014, the Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") plans were amended such that grants under the plans are settled through the issuance of treasury shares. The amendment was effective beginning with our grant in March of 2014. The final cash-settled RSU grant was paid in 2016.

The following table summarizes the PSU, RSU and Director Share Unit ("DSU") activity for the twelve months ended December 31, 2016:

For the year ended December 31, 2016	**Cash-settled LTI Plans**		**Equity-settled LTI Plans**		
(thousands of units)	**RSU**	**DSU**	**PSU**	**RSU**	**Total**
Balance, beginning of year	92	166	1,222	1,627	3,107
Granted	—	140	1,433	2,007	3,580
Vested	(89)	—	—	(594)	(683)
Forfeited	(3)	—	(590)	(342)	(935)
Balance, end of year	—	306	2,065	2,698	5,069

Cash-settled LTI Plans

For the year ended December 31, 2016 the Company recorded cash share-based compensation expense of $3.1 million (2015 - $0.9 million, 2014 - recovery of $1.2 million). For the year ended December 31, 2016, the Company made cash payments of $2.7 million related to its cash-settled plans (2015 - $15.0 million, 2014 - $14.1 million).

As of December 31, 2016, a liability of $3.9 million (December 31, 2015 - $2.3 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

For the year ended December 31, 2016 the Company recorded non-cash share-based compensation expense of $27.0 million (2015 - $18.9 million, 2014 - $9.3 million).

The following table summarizes the cumulative share-based compensation expense recognized to-date which is recorded to Paid-in Capital on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At December 31, 2016 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 22,739	$ 15,290	$ 38,029
Unrecognized share-based compensation expense	13,220	5,330	18,550
Fair value	$ 35,959	$ 20,620	$ 56,579
Weighted-average remaining contractual term (years)	1.6	1.3	

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

The Company used the Black-Scholes option pricing model to estimate the fair value of options granted under the Stock Option Plan. The Company suspended the issuance of stock options in 2014.

The following table summarizes the stock option plan activity for the year ended December 31, 2016:

Year ended December 31, 2016	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	7,580	$ 18.49
Forfeited	(1,680)	19.33
Options outstanding and exercisable, end of year	5,900	$ 18.29

At December 31, 2016, 5,900,000 options were exercisable at a weighted average exercise price of $18.29 with a final expiry in 2020, giving an aggregate intrinsic value of nil (December 31, 2015 - nil, December 31, 2014 - nil). The intrinsic value of options exercised during the year ended December 31, 2016 was nil (December 31, 2015 - $0.2 million, December 31, 2014 - $13.4 million).

d) Basic and Diluted Net Income/(Loss) Per Share

Net income/(loss) per share has been determined as follows:

(thousands, except per share amounts)	2016	2015	2014
Net income/(loss)	$ 397,416	$ (1,523,403)	$ 299,076
Weighted average shares outstanding - Basic	226,530	206,205	204,510
Dilutive impact of share-based compensation(1)	4,763	—	2,914
Weighted average shares outstanding - Diluted	231,293	206,205	207,424
Net income/(loss) per share			
Basic	$ 1.75	$ (7.39)	$ 1.46
Diluted	$ 1.72	$ (7.39)	$ 1.44

(1) For the year ended December 31, 2015, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2016, the carrying value of cash, restricted cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value due to the short-term maturity of the instruments.

At December 31, 2016 senior notes included in long-term debt had a carrying value of $716.0 million and a fair value of $771.0 million (December 31, 2015 - $1,137.2 million and $1,220.8 million, respectively).

There were no transfers between fair value hierarchy levels during the year.

b) Derivative Financial Instruments

The derivative financial assets and credits on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value.

The following tables summarize the change in fair value for the respective years:

Gain/(Loss) ($ thousands)	**December 31, 2016**	**December 31, 2015**	**December 31, 2014**	**Income Statement Presentation**
Equity Swaps	$ 3,582	$ (2,097)	$ (9,282)	General and administrative expense
Electricity Swaps	1,135	(408)	(1,275)	Operating expense
Cross Currency Interest Rate Swap:				
Interest	—	—	(580)	Interest expense
Foreign Exchange	—	—	16,128	Foreign exchange
Foreign Exchange Derivatives	—	(21,847)	6,149	Foreign exchange
Commodity Derivative Instruments:				
Oil	(96,238)	(99,790)	182,019	Commodity derivative instruments
Gas	(13,505)	(45,194)	48,879	
Total Unrealized Gain/(Loss)	$ (105,026)	$ (169,336)	$ 242,038	

The following table summarizes the effect of Enerplus' commodity derivative instruments on the Consolidated Statements of Income/(Loss):

($ thousands)	**2016**	**2015**	**2014**
Change in fair value gain/(loss)	$ (109,743)	$ (144,984)	$ 230,898
Net realized cash gain/(loss)	80,346	287,708	3,475
Commodity derivative instruments gain/(loss)	$ (29,397)	$ 142,724	$ 234,373

The following table summarizes the fair values at the respective year ends:

	December 31, 2016		**December 31, 2015**		
	Liabilities		**Assets**	**Liabilities**	
($ thousands)	**Current**	**Long-term**	**Current**	**Current**	**Long-term**
Electricity Swaps	$ 641	$ —	$ —	$ 1,776	$ —
Equity Swaps	1,044	891	—	2,324	3,193
Commodity Derivative Instruments:					
Oil	17,466	11,375	67,397	—	—
Gas	9,464	—	4,041	—	—
Total	$ 28,615	$ 12,266	$ 71,438	$ 4,100	$ 3,193

c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates and equity prices, credit risk and liquidity risk.

i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize Enerplus' price risk management positions at February 23, 2017:

Crude Oil Instruments:

Instrument Type(1)	bbls/day	US$/bbl(1)
Jan 1, 2017 – Jun 30, 2017		
WTI Swap	2,000	53.50
WTI Purchased Put	14,000	50.29
WTI Sold Call	14,000	61.14
WTI Sold Put	14,000	38.94
WCS Differential Swap	2,000	(14.75)
Jul 1, 2017 – Dec 31, 2017		
WTI Swap	2,000	53.50
WTI Purchased Put	18,000	50.61
WTI Sold Call	18,000	60.33
WTI Sold Put	18,000	39.62
WCS Differential Swap	2,000	(14.75)
Jan 1, 2018 – Dec 31, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	9,500	54.00
WTI Sold Call	9,500	63.09
WTI Sold Put	9,500	43.13
Jan 1, 2019 – Mar 31, 2019		
WTI Swap	3,000	53.73
WTI Purchased Put	1,000	56.00
WTI Sold Call	1,000	70.00
WTI Sold Put	1,000	45.00
Apr 1, 2019 – Dec 31, 2019		
WTI Purchased Put	4,000	54.69
WTI Sold Call	4,000	66.18
WTI Sold Put	4,000	43.75

(1) Transactions with a common term have been aggregated and presented as the weighted average price/bbl.

Natural Gas Instruments:

Instrument Type[1]	MMcf/day	US$/Mcf
Jan 1, 2017 – Dec 31, 2017		
NYMEX Purchased Put	50.0	2.75
NYMEX Sold Call	50.0	3.41
NYMEX Sold Put	50.0	2.06

(1) Transactions with a common term have been aggregated and presented as the weighted average price/Mcf.

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Jan 1, 2017 – Dec 31, 2017		
AESO Power Swap[1]	6.0	44.38

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

Physical Contracts:

Instrument Type	MMcf/day	US$/Mcf
Purchases:		
Jan 1, 2017 – Oct 31, 2017		
AECO-NYMEX Basis	45.0	(0.92)
Nov 1, 2017 – Oct 31, 2018		
AECO-NYMEX Basis	45.0	(0.78)
Nov 1, 2018 – Oct 31, 2019		
AECO-NYMEX Basis	45.0	(0.72)
Sales:		
Jan 1, 2017 – Oct 31, 2017		
AECO-NYMEX Basis	80.0	(0.65)
Nov 1, 2017 – Oct 31, 2018		
AECO-NYMEX Basis	80.0	(0.65)
Nov 1, 2018 – Oct 31, 2019		
AECO-NYMEX Basis	80.0	(0.64)

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations and U.S. dollar senior notes and working capital. Additionally, Enerplus' crude oil sales and a portion of its natural gas sales are based on U.S. dollar indices. Enerplus manages the currency risk relating to its senior notes through the derivative instruments detailed below.

Foreign Exchange Derivatives:

During 2014, Enerplus entered into foreign exchange collars to hedge a portion of its foreign exchange exposure on U.S. dollar denominated oil and gas sales. In 2015, Enerplus entered into foreign exchange forward rate swaps for July through December 2015 to buy US$6 million per month at an average US/CDN rate of 1.20 to partially mitigate losses on the foreign exchange collars entered into in 2014. The foreign exchange collars and forward rate swaps matured in December 2015, and during 2015 Enerplus recognized $39.2 million in net realized foreign exchange losses (2014 – gain of $0.7 million).

During 2007 Enerplus entered into foreign exchange swaps on US$54.0 million of notional debt at an average US/CDN exchange rate of 1.02. The remaining $10.8 million notional amount under the swap was settled in October 2015 in conjunction with the final principal repayment on the US$54.0 million senior notes, resulting in a realized foreign exchange gain of $3.3 million.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. These foreign exchange swaps matured between June 2017 and June 2021 in conjunction with the principal repayments on the US$225.0 million senior notes. During 2015 Enerplus unwound these swaps and recognized a gain of $39.9 million.

Interest Rate Risk:

At December 31, 2016, approximately 97% of Enerplus' debt was based on fixed interest rates and 3% was based on floating interest rates. At December 31, 2016 Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 14. Enerplus has entered into various equity swaps maturing between 2017 and 2018 and has effectively fixed the future settlement cost on 470,000 shares at a weighted average price of $16.89 per share.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables.

Enerplus mitigates credit risk through credit management techniques, including conducting financial assessments to establish and monitor counterparties' credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees, or third party credit insurance where warranted. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At December 31, 2016 approximately 58% of Enerplus' marketing receivables were with companies considered investment grade.

At December 31, 2016 approximately $1.9 million or 2% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2016 was $3.3 million (December 31, 2015 - $3.2 million).

iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, access to capital markets, as well as acquisition and divestment activity.

16) COMMITMENTS, CONTINGENCIES AND GUARANTEES

a) Commitments

Enerplus has the following minimum annual commitments at December 31, 2016:

		Minimum Annual Commitment Each Year					
($ thousands)	Total	2017	2018	2019	2020	2021	Thereafter
Bank credit facility(1)	$ 23,226	$ —	$ —	$ 23,226	$ —	$ —	$ —
Senior notes(1)	745,599	29,539	29,539	59,539	109,564	109,564	407,854
Transportation commitments	293,624	31,891	29,104	24,618	22,800	19,523	165,688
Processing commitments	42,931	11,427	10,136	10,136	1,550	1,550	8,132
Drilling and completions	29,137	29,137	—	—	—	—	—
Office lease commitments	88,345	12,197	12,006	10,494	10,816	10,848	31,984
Sublease recoveries	(9,293)	(1,956)	(1,613)	(1,709)	(1,759)	(1,516)	(740)
Net office lease commitments	79,052	10,241	10,393	8,785	9,057	9,332	31,244
Total commitments(2)(3)	$ 1,213,569	$ 112,235	$ 79,172	$ 126,304	$ 142,971	$ 139,969	$ 612,918

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2016 foreign exchange rate of 1.3427.

b) Contingencies

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

c) Guarantees

(i) Corporate indemnities have been provided by Enerplus to all directors and officers for various items including costs to settle suits or actions due to their association with Enerplus. Enerplus has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of Enerplus.

(ii) Enerplus may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents Enerplus from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

17) GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2016 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 233,391	$ 489,341	$ 722,732
Operating expenses	134,593	113,324	247,917
Depletion, depreciation and accretion	126,062	202,902	328,964
Property, plant and equipment	304,048	434,382	738,430
Deferred income tax asset	183,691	549,672	733,363
Goodwill	451,121	200,542	651,663

As at and for the year ended December 31, 2015 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 369,559	$ 514,833	$ 884,392
Operating expenses	217,077	123,406	340,483
Depletion, depreciation and accretion	198,641	309,538	508,179
Property, plant and equipment	435,604	750,669	1,186,273
Deferred income tax asset	157,356	358,729	516,085
Goodwill	451,121	206,710	657,831

As at and for the year ended December 31, 2014 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 689,135	$ 837,059	$ 1,526,194
Operating expenses	254,135	94,461	348,596
Depletion, depreciation and accretion	236,027	331,615	567,642
Property, plant and equipment	1,028,436	1,624,629	2,653,065
Deferred income tax asset	104,752	192,560	297,312
Goodwill	451,121	173,269	624,390

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2016	December 31, 2015	December 31, 2014
Accounts receivable	$ 16,982	$ 37,064	$ (8,392)
Other current assets	2,154	(2,634)	(6,777)
Accounts payable	(4,061)	(47,260)	(37,245)
	$ 15,075	$ (12,830)	$ (52,414)

b) Other

($ thousands)	December 31, 2016	December 31, 2015	December 31, 2014
Income taxes paid/(received)	$ (21,244)	$ (22,274)	$ 18,087
Interest paid	$ 48,545	$ 65,498	$ 58,416

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SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2016	2015	2016	2015
Financial (000's)				
Adjusted Funds Flow[4]	$ 107,730	$ 102,674	$ 305,605	$ 493,101
Dividends to Shareholders	7,214	22,717	35,439	131,955
Net Income/(Loss)	840,325	(624,987)	397,416	(1,523,403)
Debt Outstanding, net of Cash and Restricted Cash	375,520	1,216,184	375,520	1,216,184
Capital Spending	57,462	89,490	209,135	493,403
Property and Land Acquisitions	118,452	8,794	126,126	9,552
Property Divestments	389,750	83,236	670,364	286,614
Debt to Adjusted Funds Flow Ratio[4]	1.2x	2.5x	1.2x	2.5x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 3.49	$ (3.03)	$ 1.75	$ (7.39)
Net Income/(Loss) - Diluted	3.43	(3.03)	1.72	(7.39)
Weighted Average Number of Shares Outstanding (000's)	240,483	206,517	226,530	206,205
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 32.81	$ 23.81	$ 25.88	$ 27.07
Royalties and Production Taxes	(7.60)	(4.75)	(5.77)	(5.63)
Commodity Derivative Instruments	1.12	7.50	2.36	7.40
Cash Operating Expenses	(7.22)	(8.68)	(7.31)	(8.75)
Transportation Costs	(3.44)	(2.98)	(3.14)	(2.95)
General and Administrative Expenses	(1.63)	(1.75)	(1.75)	(2.09)
Cash Share-Based Compensation	(0.17)	0.16	(0.09)	(0.02)
Interest, Foreign Exchange and Other Expenses	(0.97)	(2.94)	(1.28)	(2.78)
Current Tax Recovery	0.26	0.07	0.07	0.43
Adjusted Funds Flow[4]	$ 13.16	$ 10.44	$ 8.97	$ 12.68

SELECTED OPERATING RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2016	2015	2016	2015
Average Daily Production[2]				
Crude Oil (bbls/day)	37,128	41,135	38,353	41,639
Natural Gas Liquids (bbls/day)	4,413	5,092	4,903	4,763
Natural Gas (Mcf/day)	284,515	364,065	299,214	360,733
Total (BOE/day)	88,960	106,905	93,125	106,524
% Crude Oil and Natural Gas Liquids	47%	43%	46%	44%
Average Selling Price[2][3]				
Crude Oil (per bbl)	$ 53.91	$ 43.04	$ 44.84	$ 48.43
Natural Gas Liquids (per bbl)	21.31	16.61	15.29	18.06
Natural Gas (per Mcf)	2.89	1.89	2.06	2.15
Net Wells Drilled	5	2	25	46

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(3) Before transportation costs, royalties and commodity derivative instruments.
(4) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the following MD&A.

Average Benchmark Pricing	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015
WTI crude oil (US$/bbl)	$ 49.29	$ 42.18	$ 43.32	$ 48.80
AECO natural gas – monthly index (CDN$/Mcf)	2.81	2.65	2.09	2.77
AECO natural gas – daily index (CDN$/Mcf)	3.09	2.47	2.16	2.69
NYMEX natural gas – last day (US$/Mcf)	2.98	2.27	2.46	2.66
US/CDN average exchange rate	1.33	1.34	1.32	1.28

Share Trading Summary For the twelve months ended December 31, 2016	CDN(1) – ERF (CDN$)	U.S.(2) – ERF (US$)
High	$ 13.55	$ 10.33
Low	$ 2.68	$ 1.84
Close	$ 12.74	$ 9.48

(1) TSX and other Canadian trading data combined.
(2) NYSE and other U.S. trading data combined.

2016 Dividends per Share	CDN$	US$(1)
First Quarter Total	$ 0.09	$ 0.07
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Fourth Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.18	$ 0.13

(1) CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

Financial and Operational Highlights

- Fourth quarter 2016 production averaged 88,960 BOE per day, bringing annual average 2016 production to 93,125 BOE per day, in line with guidance of 93,000 BOE per day. Fourth quarter 2016 crude oil and natural gas liquids production averaged 41,541 barrels per day, impacted by severe weather in North Dakota during the quarter. Annual average 2016 liquids production was 43,256 barrels per day, within the guidance range of 43,000 to 44,000 barrels per day.

- Enerplus realized strong value from its non-core divestments in 2016, selling 13,500 BOE per day (60% natural gas) of production for aggregate proceeds of $670.4 million.

- The Company reported fourth quarter 2016 net income of $840.3 million, or $3.43 per diluted share. Net income was impacted by a gain on the sale of the Company's non-operated North Dakota properties of $339.4 million, and a non-cash deferred tax recovery of $567.8 million primarily as a result of the reversal of a portion of the valuation allowance on the Company's deferred tax asset. For the year ended December 31, 2016, Enerplus reported net income of $397.4 million, or $1.72 per diluted share, compared with a net loss of $1,523.4 million, or $7.39 per share, for the comparable 2015 period.

- Enerplus generated fourth quarter 2016 adjusted funds flow of $107.7 million, an increase of 34% from the previous quarter as a result of stronger commodity prices in the fourth quarter. The Company generated full year 2016 adjusted funds flow of $305.6 million, down 38% from the comparable 2015 period due to lower average commodity prices and lower hedging gains in 2016.

- Enerplus delivered strong operating cost performance in 2016 reflecting efficiency improvements and the divestment of higher cost properties. Fourth quarter operating expenses were $7.15 per BOE, a reduction of 18% compared to the same period in 2015. Full year 2016 operating expenses were $7.27 per BOE, a reduction of 17% compared to 2015.

- Fourth quarter 2016 cash G&A expenses were $1.63 per BOE, a reduction of 7% compared to the same period in 2015. Full year 2016 cash G&A expenses were $1.75 per BOE, a reduction of 16% compared to 2015. Enerplus' lower G&A cost structure is, in part, a result of a reduction in staffing levels related to non-core asset divestments.

- Transportation expense in the fourth quarter of 2016 was $3.44 per BOE, up slightly from the previous quarter. Full year 2016 transportation expense was $3.14 per BOE, a 6% increase from the prior year period.

- Capital spending in the fourth quarter of 2016 was $57.5 million, with approximately 71% allocated to North Dakota. Full year 2016 capital spending totaled $209.1 million, slightly below annual 2016 guidance of $215.0 million.

- Enerplus significantly strengthened its balance sheet during 2016 having reduced its total debt, net of cash and restricted cash, by 69%, or $840.7 million, over the twelve-month period. Total debt, net of cash and restricted cash, at December 31, 2016 was $375.5 million, and was comprised of $23.2 million of bank indebtedness and $745.6 million of senior notes less $393.3 million in cash, including $392.0 million in restricted cash. The restricted cash balance reflects proceeds from the sale of the Company's non-operated North Dakota properties which were placed in escrow in order to facilitate possible future like-kind transactions in accordance with U.S. federal tax regulations. Net debt to adjusted funds flow at year-end was 1.2 times.

Reserves Highlights

- Replaced 126% of 2016 production, adding 42.6 MMBOE (42% crude oil and natural gas liquids) of proved plus probable ("2P") reserves from development activities (including revisions).

- Material reserves growth was realized in Enerplus' North Dakota and Marcellus assets. The Company replaced 207% of 2016 North Dakota production, excluding production from Enerplus' non-operated North Dakota assets which were sold at the end of 2016, adding 17.5 MMBOE of 2P reserves (including revisions). The Company also replaced 175% of 2016 Marcellus production, adding 125.0 Bcf of 2P reserves (including revisions).

- Finding and development ("F&D") costs for proved developed producing ("PDP") reserves decreased by 60% to $4.77 per BOE for 2016, generating a PDP reserves recycle ratio of 2.0 times based on a 2016 operating netback (before hedging) of $9.66 per BOE. Enerplus' three-year average PDP reserves F&D cost was $10.37 per BOE.

2016 HIGHLIGHTS

- F&D costs for 2P reserves decreased by 43% to $4.82 per BOE for 2016, including future development costs (“FDC”), generating a 2P reserves recycle ratio of 2.0 times. Enerplus’ three-year average 2P reserves F&D cost, including FDC, was $8.11 per BOE.

- Enerplus sold various non-core properties in 2016 representing 37.3 MMBOE of 2P reserves at a combined value of $20.38 per BOE. Total 2P reserves, net of divestments, were 382.5 MMBOE at year-end 2016, representing a 6% decrease from year-end 2015. Excluding acquisitions and divestments, 2P reserves increased by 2% in 2016.

- 2P reserves were comprised of 51% crude oil and natural gas liquids and 49% natural gas at year-end 2016.

- Total proved reserves account for 70% of 2P reserves. PDP reserves represent 71% of total proved reserves and 50% of 2P reserves.

EXHIBIT 99.3

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated February 23, 2017 and is to be read in conjunction with the audited Consolidated Financial Statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of this MD&A for further information.

BASIS OF PRESENTATION

The Financial Statements and notes have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Certain prior period amounts have been restated to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil 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. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests, unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101–Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities.

In accordance with U.S. GAAP, oil and natural gas sales are presented net of royalties in the Financial Statements. Under International Financial Reporting Standards, industry standard is to present oil and natural gas sales before deduction of royalties and as such this MD&A presents production, oil and natural gas sales, and BOE measures before deduction of royalties to remain comparable with our peers.

The following table provides a reconciliation of our production volumes:

	Year ended December 31,		
Average Daily Production Volumes	**2016**	**2015**	**2014**
Company interest production volumes			
Crude oil (bbls/day)	38,353	41,639	40,208
Natural gas liquids (bbls/day)	4,903	4,763	3,565
Natural gas (Mcf/day)	299,214	360,733	356,142
Company interest production volumes (BOE/day)	93,125	106,524	103,130
Royalty volumes			
Crude oil (bbls/day)	7,198	7,471	7,731
Natural gas liquids (bbls/day)	932	971	775
Natural gas (Mcf/day)	50,270	59,077	55,114
Royalty volumes (BOE/day)	16,508	18,288	17,692
Net production volumes			
Crude oil (bbls/day)	31,155	34,168	32,477
Natural gas liquids (bbls/day)	3,971	3,792	2,790
Natural gas (Mcf/day)	248,944	301,656	301,028
Net production volumes (BOE/day)	76,617	88,236	85,438

2016 FOURTH QUARTER OVERVIEW

Fourth quarter production averaged 88,960 BOE/day, in line with our target of 89,000 BOE/day, and a decrease of 3,117 BOE/day compared to third quarter production of 92,077 BOE/day. In the U.S. production during the fourth quarter was impacted by approximately 1,700 BOE/day of price related curtailments in the Marcellus and fewer on-streams in North Dakota along with severe winter weather. Canadian production was consistent with the prior quarter, with production from our November asset acquisition of a Canadian waterflood property offsetting price related shut-ins and minor non-core asset divestments. Operating costs increased somewhat in the fourth quarter, to $58.5 million or $7.15/BOE from $56.2 million or $6.64/BOE in the third quarter, due to additional weather related costs in December.

We reported net income of $840.3 million and adjusted funds flow of $107.7 million in the fourth quarter compared to a net loss of $100.7 million and adjusted funds flow of $80.1 million in the third quarter. Both net income and adjusted funds flow benefited from a $29.1 million or 15% increase in net oil and natural gas sales compared to the third quarter, with improved pricing offsetting the impact of lower production volumes. Net income also increased as a result of a non-cash deferred tax recovery of $567.8 million due to the reversal of a portion of the valuation allowance on our deferred tax asset and a $339.4 million gain on the sale of non-operated North Dakota properties.

On November 15, 2016, we closed the previously announced purchase of a Canadian waterflood property for proceeds of $110.3 million.

On December 30, 2016, we closed the previously announced sale of our non-operated North Dakota properties with production of approximately 5,000 BOE/day for proceeds of $392.0 million.

Selected Fourth Quarter Canadian and U.S. Financial Results

	Three months ended December 31, 2016			Three months ended December 31, 2015		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	12,417	24,711	37,128	13,790	27,345	41,135
Natural gas liquids (bbls/day)	1,160	3,253	4,413	1,771	3,321	5,092
Natural gas (Mcf/day)	68,437	216,078	284,515	135,898	228,167	364,065
Total average daily production (BOE/day)	24,983	63,977	88,960	38,210	68,695	106,905
Pricing[2]						
Crude oil (per bbl)	$ 48.44	$ 56.66	$ 53.91	$ 38.11	$ 45.53	$ 43.04
Natural gas liquids (per bbl)	36.33	15.96	21.31	28.77	10.13	16.61
Natural gas (per Mcf)	3.13	2.82	2.89	2.46	1.55	1.89
Capital Expenditures						
Capital spending	$ 10.2	$ 47.3	$ 57.5	$ 26.8	$ 62.7	$ 89.5
Acquisitions	111.2	7.2	118.4	0.7	8.1	8.8
Divestments	(1.5)	(388.3)	(389.8)	0.9	(84.1)	(83.2)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 78.9	$ 189.7	$ 268.6	$ 84.0	$ 150.2	$ 234.2
Royalties	(11.0)	(40.1)	(51.1)	(9.0)	(25.8)	(34.8)
Production taxes	(0.4)	(10.6)	(11.0)	(1.5)	(10.5)	(12.0)
Cash operating expenses	(30.7)	(28.4)	(59.1)	(54.4)	(30.9)	(85.3)
Transportation costs	(3.2)	(25.0)	(28.2)	(5.2)	(24.1)	(29.3)
Netback before hedging	$ 33.6	$ 85.6	$ 119.2	$ 13.9	$ 58.9	$ 72.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 33.0	$ —	$ 33.0	$ (31.1)	$ —	$ (31.1)
General and administrative expense[4]	21.0	7.0	28.0	10.4	8.1	18.5
Current income tax recovery	—	(2.1)	(2.1)	(0.4)	(0.3)	(0.7)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.
(4) Includes share-based compensation.

Comparing the fourth quarter of 2016 with the same period in 2015:

- Average daily production was 88,960 BOE/day, down 17% or approximately 17,945 BOE/day from 106,905 BOE/day in 2015 primarily due to our non-core Canadian asset divestments and lower capital spending.

- Despite a significant reduction in capital spending, U.S. production declined only modestly over the period as a result of strong well performance. This was offset somewhat by the divestment of 1,000 BOE/day of our non-operated North Dakota properties during the fourth quarter of 2015. U.S. crude oil production decreased 10% or 2,634 BOE/day from the fourth quarter of 2016 to the fourth quarter of 2015, while natural gas production decreased 5% or 2,015 BOE/day over the same period.

- Capital spending decreased to $57.5 million compared to $89.5 million in the fourth quarter of 2015. The majority of our capital investment in the fourth quarter was focused on our core areas, with spending of $41.1 million on our North Dakota crude oil properties, $10.2 million on our Canadian crude oil waterflood properties and $4.2 million on our Marcellus natural gas properties.

- Operating expenses decreased to $58.5 million ($7.15/BOE) compared to $85.6 million ($8.71/BOE) in the fourth quarter of 2015 as a result of ongoing cost efficiencies and the divestment of higher operating cost Canadian properties throughout 2016.

- Cash general and administrative ("G&A") expenses decreased to $13.4 million ($1.63/BOE) compared to $17.2 million ($1.75/BOE) in 2015 due to reductions in staffing levels and the success of our ongoing cost saving initiatives.

- We reported net income of $840.3 million in the fourth quarter of 2016 compared to a net loss of $625.0 million in the fourth quarter of 2015. The improvement year over year was primarily the result of a non-cash deferred tax recovery of $567.8 million due to the reversal of a portion of our valuation allowance on our deferred tax asset, compared to a non-cash deferred tax provision of $294.4 million on our deferred tax asset in the same period of 2015. Net income also benefitted from a gain of $339.4 million on the sale of our non-operated North Dakota property and a $221.0 million decrease in the non-cash impairment charge on our crude oil and natural gas assets compared to the fourth quarter of 2015.

- Adjusted funds flow increased to $107.7 million compared to $102.7 million in the fourth quarter of 2015. The increase in adjusted funds flow was a result of significantly higher commodity prices, which were offset in part by lower production volumes and a $64.1 million decrease in cash gains on commodity hedges.

2016 OVERVIEW AND 2017 OUTLOOK

Summary of Guidance and Results	Original 2016 Guidance	Revised 2016 Guidance	2016 Results	2017 Guidance
Capital spending ($ millions)	$200	$215	$209	$450
Average annual production (BOE/day)	90,000 - 94,000	93,000	93,125	86,000 – 90,000
Crude oil and natural gas liquids volumes (bbls/day)	43,000 - 45,000	43,000 - 44,000	43,256	40,000 – 43,000
Average royalty and production tax rate (% of oil and natural gas sales)	23%	22%	22%	23%
Operating expenses (per BOE)	$9.50	$7.50	$7.27	$7.85
Transportation costs (per BOE)	$3.30	$3.15	$3.14	$3.90
Cash G&A expenses (per BOE)	$2.10	$1.80	$1.75	$1.80

2016 Overview

We improved our financial position in 2016 despite the weakness and volatility in commodity prices. We achieved this through ongoing cost reductions, strong operational results, a disciplined capital program and a successful non-core asset divestment program.

Average annual production was 93,125 BOE/day, consistent with our guidance of 93,000 BOE/day. Crude oil and liquids volumes were 43,256 bbls/day, within our guidance range of 43,000 – 44,000 bbls/day.

Our capital spending for the year totaled $209.1 million, slightly below our guidance of $215 million due to weather related deferrals of spending in the fourth quarter.

Operating expenses and cash G&A expenses came in under our guidance, at $7.27/BOE and $1.75/BOE, respectively, compared to guidance of $7.50/BOE and $1.80/BOE, respectively. The outperformance was a result of our ongoing cost saving initiatives and our continued effort to focus our business through the sale of higher cost, non-core assets.

Net income for 2016 was $397.4 million, a significant increase from our net loss of $1,523.4 million in 2015 primarily due to a $1,051.3 million decrease in non-cash asset impairments, along with $578.5 million in realized gains on asset divestments and senior note prepayments.

Adjusted funds flow decreased 38% to $305.6 million in 2016 from $493.1 million in 2015. This was due to a $161.7 million decrease in net oil and gas sales over the period as a result of lower production volumes and weaker commodity prices, along with a $207.4 million decrease in realized gains on commodity hedges. These reductions were offset by significant cost savings in operating, interest and cash G&A expenses.

We continued to focus our portfolio during 2016, divesting of certain non-operated crude oil assets in the U.S. and lower margin crude oil and natural gas assets in Canada for aggregate proceeds of $670.4 million. These assets had associated production of approximately 13,500 BOE/day.

On May 31, 2016, we completed an equity financing of 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million net of issue costs).

Proceeds from both the asset divestments and equity financing were used to reduce our total debt, net of cash and restricted cash, by 69% or $840.7 million compared to the prior year. Net debt at December 31, 2016 was $375.5 million, comprised of $23.2 million of bank indebtedness and $745.6 million of senior notes less $393.3 million in cash and restricted cash. At December 31, 2016, we were approximately 3% drawn on our $800 million senior unsecured bank credit facility.

2017 Outlook

Our focus for 2017 is to deliver profitable growth and generate strong returns on capital while maintaining our balance sheet strength. Accordingly, we have increased our capital budget for 2017 to $450 million, with the majority directed to our North Dakota crude oil properties. We expect this spending level to generate significant liquids growth, with a 25% increase in liquids production from the beginning of 2017 to the fourth quarter of 2017, driven by 50% growth in our total North Dakota production over the same period.

Annual 2017 production is expected to average between 86,000 – 90,000 BOE/day, with crude oil and natural gas liquids production expected to average between 40,000 – 43,000 bbls/day. Following a limited completions program in North Dakota in the fourth quarter of 2016, capital spending is forecast to begin to ramp-up in the first half of 2017, driving strong liquids production growth in the back half of the year. Total fourth quarter production is expected to average 92,000 – 97,000 BOE/day, with a fourth quarter liquids production target of 45,000 - 50,000 bbls/day.

To support our 2017 capital program, we have increased our 2017 crude oil hedging program to 63% of our forecast crude oil production volumes, after royalties, and 23% of our natural gas production, after royalties. We have also added crude oil hedges in 2018 and 2019 on approximately 44% and 14%, respectively, based on our forecasted 2017 net crude oil production.

Operating expenses are expected to average approximately $7.85/BOE in 2017, modestly higher than 2016 levels as we expect to increase our corporate weighting of liquids production in 2017.

We expect cash G&A expenses in 2017 to average approximately $1.80/BOE. Although we expect total costs to decrease year over year, our per BOE expenses will remain flat due to lower production volumes.

Transportation costs are expected to average $3.90/BOE in 2017, an increase from 2016 levels. The increase is largely attributable to additional firm transportation commitments in the Marcellus that came into effect in August 2016 that deliver to higher priced markets, along with lower production volumes due to the non-operated year-end 2016 divestment and a weaker Canadian dollar projected in 2017 compared to 2016.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2016	2015	2014
Crude oil (bbls/day)	38,353	41,639	40,208
Natural gas liquids (bbls/day)	4,903	4,763	3,565
Natural gas (Mcf/day)	299,214	360,733	356,142
Total daily sales (BOE/day)	93,125	106,524	103,130

Production in 2016 averaged 93,125 BOE/day, in line with our guidance of 93,000 BOE/day. Crude oil and liquids volumes were 43,256 bbls/day, within our guidance range of 43,000 – 44,000 bbls/day. The 13% decrease in average production compared to the prior year was primarily due to the sale of non-core properties during the fourth quarter of 2015 and throughout the first three quarters of 2016 with associated production of approximately 11,800 BOE/day, and our reduced capital spending program compared to the prior year.

Our U.S. production decreased a modest 2% compared to 2015 despite our reduced capital spending. The decrease was primarily due to a 1,200 BOE/day or 4% reduction in Marcellus natural gas production due to lower investment and price related production curtailments during the year. In North Dakota, strong production from our crude oil properties offset the impact of decline and the fourth quarter 2015 sale of a portion of our non-operated properties.

Canadian production volumes decreased 12,310 BOE/day or 31% compared to the prior year, largely due to asset divestments. Price related shut-ins and asset declines also impacted Canadian production, but were offset somewhat by our November, 2016 acquisition of a Canadian waterflood property.

Our crude oil and natural gas liquids production accounted for 46% of our total average daily production in 2016, compared to 44% in 2015.

In 2015, production increased 3% over 2014 to average 106,524 BOE/day. Crude oil production increased 4% from the prior year due to 6,000 BOE/day or 28% growth in our North Dakota crude oil volumes. Our natural gas production was relatively consistent with 2014 at 360,733 Mcf/day, with 8% growth in our Marcellus production offset by decline in Canadian natural gas volumes over the same period.

2017 Guidance

We expect annual average production for 2017 of 86,000 – 90,000 BOE/day, including 40,000 – 43,000 bbls/day of crude oil and natural gas liquids. As a result of our increased capital spending program of $450 million, we expect strong production growth in the second half of the year, with liquids production expected to grow 25% from the beginning of 2017 to the end of the year. Accordingly, we are providing fourth quarter total average production guidance of 92,000 – 97,000 BOE/day and fourth quarter liquids production guidance of 45,000 – 50,000 bbls/day. This guidance includes the full year impact of our 2016 acquisitions and divestments, including the December 30, 2016 sale of 5,000 BOE/day non-operated North Dakota properties and the November 15, 2016 acquisition of a Canadian waterflood property.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table summarizes our average selling prices, benchmark prices and differentials:

Pricing (average for the period)	2016	2015	2014
Benchmarks			
WTI crude oil (US$/bbl)	$ 43.32	$ 48.80	$ 93.00
AECO natural gas – monthly index ($/Mcf)	2.09	2.77	4.42
AECO natural gas – daily index ($/Mcf)	2.16	2.69	4.51
NYMEX natural gas – last day (US$/Mcf)	2.46	2.66	4.41
US/CDN average exchange rate	1.32	1.28	1.10
US/CDN period end exchange rate	1.34	1.38	1.16
Enerplus selling price[1]			
Crude oil ($/bbl)	$ 44.84	$ 48.43	$ 86.28
Natural gas liquids ($/bbl)	15.29	18.06	51.72
Natural gas ($/Mcf)	2.06	2.15	3.94
Average differentials			
MSW Edmonton – WTI (US$/bbl)	$ (3.21)	$ (3.93)	$ (7.17)
WCS Hardisty – WTI (US$/bbl)	(13.84)	(13.52)	(19.40)
Transco Leidy monthly – NYMEX (US$/Mcf)	(1.15)	(1.52)	(1.95)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(1.21)	(1.58)	(2.04)
AECO monthly – NYMEX (US$/Mcf)	(0.89)	(0.50)	(0.41)
Enerplus realized differentials[1]			
Canada crude oil – WTI (US$/bbl)	$ (13.21)	$ (13.34)	$ (17.36)
Canada natural gas – NYMEX (US$/Mcf)	(0.80)	(0.44)	(0.34)
Bakken crude oil – WTI (US$/bbl)	(7.46)	(9.44)	(12.94)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.93)	(1.37)	(1.43)

(1) Before transportation costs, royalties and commodity derivative instruments.

CRUDE OIL AND NATURAL GAS LIQUIDS

Our realized crude oil price in 2016 averaged $44.84/bbl, a 7% decrease compared to 2015. Benchmark WTI crude oil prices fell by 11% versus 2015 due to the continued oversupply of crude oil in the global markets for most of the year. In the fourth quarter of 2016, the Organization of the Petroleum Exporting Countries ("OPEC") and certain non-OPEC nations agreed to reduce production by approximately 1.8 million bbls/day through June 2017, which resulted in WTI prices strengthening at the end of the year to US$53.72/bbl.

Our Bakken sales price differential improved by 21% year over year, averaging US$7.46/bbl below WTI due to declining regional production and stronger local refinery demand. With the Dakota Access Pipeline expected to be completed and in service around mid-year 2017, increasing regional takeaway capacity, we are expecting our 2017 Bakken crude oil differential to improve to US$4.50/bbl below WTI, from our previous guidance of US$6.00/bbl below WTI. Canadian light sweet crude prices also improved, resulting in our Canadian realized price differentials to WTI narrowing slightly compared to the prior year.

We realized an average of $15.29/bbl on our natural gas liquids production, which was 15% lower than 2015 and largely in line with changes in underlying crude oil prices.

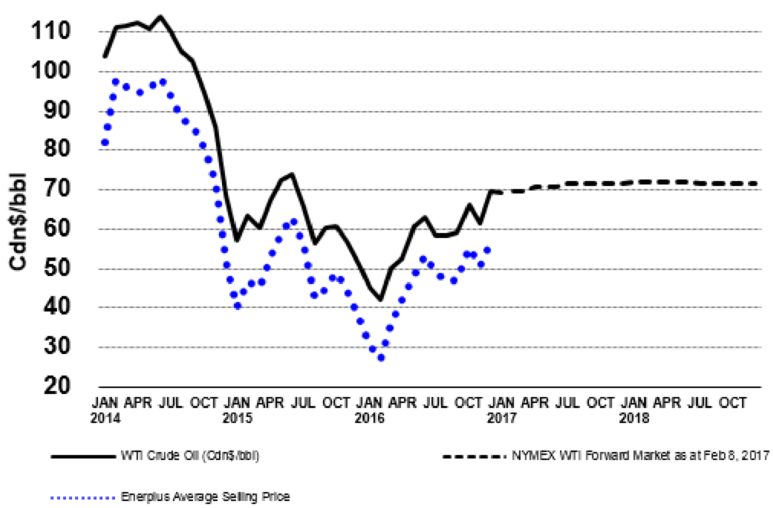
NATURAL GAS

Our realized natural gas price averaged $2.06/Mcf in 2016, a 4% decrease from 2015 realized prices but considerably stronger than the changes in benchmark prices during the period. NYMEX prices fell by 8% and AECO monthly prices fell by 25% compared to 2015 in response to excess inventories due to a warm winter in early 2016. However, with lower production levels and warmer than average summer temperatures in the U.S., NYMEX prices improved substantially over the course of the year and into 2017. In Alberta, concerns over congestion on regional pipelines due to continued production growth resulted in AECO prices averaging US$0.89/Mcf below NYMEX in 2016 compared to US$0.50/Mcf below NYMEX in 2015. Our overall realized natural gas price outperformed the benchmarks due to much stronger Marcellus basis differentials and the positive impact of our term AECO physical sales with fixed basis differentials at prices much narrower than where AECO basis market prices averaged.

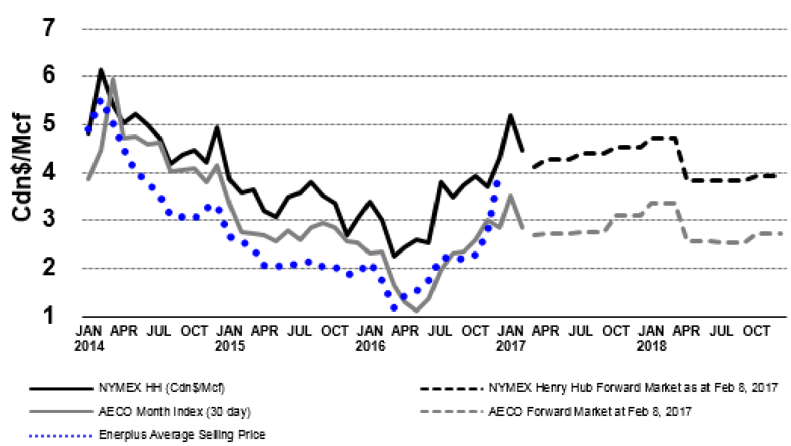
In the Marcellus, the Tennessee Gas Pipeline Zone 4 - 300 Leg and Transco Leidy monthly benchmark differentials averaged US$1.21/Mcf and US$1.15/Mcf below NYMEX compared to US$1.58/Mcf and US$1.52/Mcf below NYMEX in 2015. The strengthening in local Marcellus prices was due to additional pipeline capacity coming into service, as well as higher weather related demand in the region. Our realized sales price benefitted from August to December 2016 as we began to transport 30,000 Mcf/day of production to markets south of the Marcellus producing region, allowing us to realize sales prices closer to NYMEX pricing. This resulted in an average Marcellus realized sales price differential before transportation costs of US$0.93/Mcf below NYMEX, a 32% improvement from 2015.

We expect our realized Marcellus differentials in 2017 to continue to improve due to further pipeline capacity additions and stronger regional demand alleviating some of the constraints in the region. There is the potential for differentials to widen in certain periods of the year as seasonal demand falls and until sufficient pipeline capacity is built to fully relieve the congestion. We expect our Marcellus natural gas realized differential to average US$0.90/Mcf below NYMEX in 2017.

Monthly Crude Oil Prices



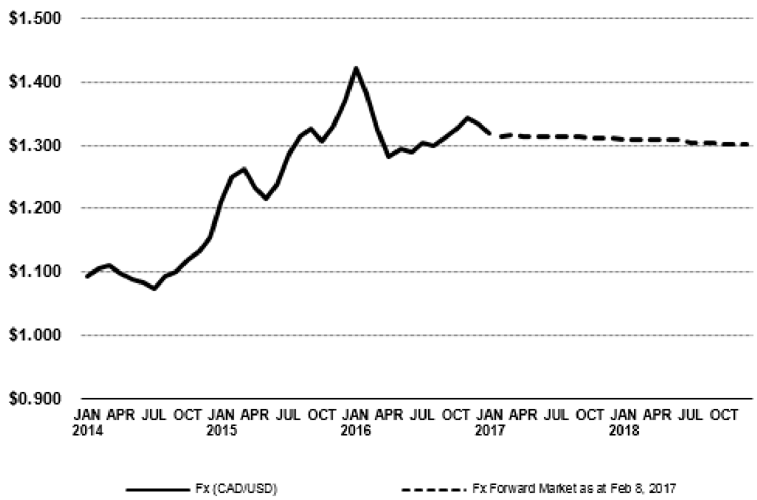
Monthly Natural Gas Prices



FOREIGN EXCHANGE

The Canadian dollar was volatile throughout 2016, beginning the year near a thirteen year low of 1.47 USD/CDN and strengthening to 1.25 USD/CDN in late April before closing the year at 1.34 USD/CDN. Overall, the Canadian dollar weakened relative to the U.S. dollar, averaging 1.32 USD/CDN. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the weaker Canadian dollar also increases our U.S. dollar denominated costs, capital spending and the cost of our U.S. dollar denominated senior notes.

Monthly USD/CDN Exchange Rate



Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions.

As of February 23, 2017, we have hedged approximately 18,000 bbls/day of our crude oil production for 2017, which represents approximately 63% of our forecasted 2017 crude oil production, after royalties. For 2018, we have hedged 12,500 bbls/day, which represents approximately 44% of our forecasted 2017 crude oil production, after royalties. We have also added hedges through 2019 to protect the long term economics of a portion of our capital program. Our crude oil hedges are predominantly three way collars, which consist of a sold put, a purchased put and a sold call. When WTI prices settle below the sold put strike in any given month, the three way collars provide a limited amount of protection above the WTI index prices equal to the difference between the strike price of the purchased and sold puts. Overall, we continue to expect our crude oil hedge contracts to protect a significant portion of our adjusted funds flow.

As of February 23, 2017, we have hedged approximately 50,000 Mcf/day of our natural gas production for 2017 using NYMEX three way collars. This represents approximately 23% of our 2017 forecasted 2017 natural gas production, after royalties. When NYMEX prices settle below the sold put strike price in any given month, the three way collars provide a limited amount of protection above the NYMEX index prices equal to the value between the strike price of the purchased and sold puts.

The following is a summary of our financial contracts in place at February 23, 2017, expressed as a percentage of our anticipated production volumes, after royalties, for 2017:

	WTI Crude Oil (US$/bbl)[(1)]					NYMEX Natural Gas (US$/Mcf)[(1)]
	Jan 1, 2017 – Jun 30, 2017	Jul 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Jan 1, 2017 – Dec 31, 2017
Swaps						
Sold Swaps	$ 53.50	$ 53.50	$ 53.73	$ 53.73	-	-
%	7%	7%	11%	11%	-	-
Three Way Collars						
Sold Puts	$ 38.94	$ 39.62	$ 43.13	$ 45.00	$ 43.75	$ 2.06
%	49%	63%	33%	3%	14%	23%
Purchased Puts	$ 50.29	$ 50.61	$ 54.00	$ 56.00	$ 54.69	$ 2.75
%	49%	63%	33%	3%	14%	23%
Sold Calls	$ 61.14	$ 60.33	$ 63.09	$ 70.00	$ 66.18	$ 3.41
%	49%	63%	33%	3%	14%	23%

(1) Based on weighted average price (before premiums) assuming average annual production of 88,000 BOE/day for 2017, less royalties and production taxes of 23%.

We did not have any foreign exchange contracts in place during 2016. In comparison, during 2015, we recorded realized foreign exchange losses of $39.2 million on foreign exchange costless collars and foreign exchange gains of $39.9 million and $3.3 million, respectively, on the unwind of our US$175 million foreign exchange swap and the final settlement of the foreign exchange swap on our US$54 million senior notes.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)

($ millions)	2016	2015	2014
Cash gains/(losses):			
Crude oil	$ 75.0	$ 217.2	$ 7.0
Natural gas	5.3	70.5	(3.5)
Total cash gains/(losses)	$ 80.3	$ 287.7	$ 3.5
Non-cash gains/(losses):			
Crude oil	$ (96.2)	$ (99.8)	$ 182.0
Natural gas	(13.5)	(45.2)	48.9
Total non-cash gains/(losses)	$ (109.7)	$ (145.0)	$ 230.9
Total gains/(losses)	$ (29.4)	$ 142.7	$ 234.4

(Per BOE)	2016	2015	2014
Total cash gains/(losses)	$ 2.36	$ 7.40	$ 0.09
Total non-cash gains/(losses)	(3.22)	(3.73)	6.14
Total gains/(losses)	$ (0.86)	$ 3.67	$ 6.23

During 2016, we realized cash gains of $75.0 million on our crude oil contracts and $5.3 million on our natural gas contracts. In comparison, in 2015 we realized cash gains of $217.2 million on our crude oil contracts and $70.5 million on our natural gas contracts. During 2014, we realized cash gains of $7.0 million on our crude oil contracts and cash losses of $3.5 million on our natural gas contracts. The cash gains in each year were due to contracts which provided floor protection above market prices, while cash losses were a result of natural gas prices rising above our fixed price swap positions.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. The fair value of our crude oil and natural gas contracts represented net loss positions of $28.8 million and $9.5 million, respectively, at December 31, 2016, and net gain positions of $67.4 million and $4.0 million, respectively, at December 31, 2015. The change in fair value of our crude oil and natural gas contracts represented losses of $96.2 million and $13.5 million, respectively, during 2016 and losses of $99.8 million and $45.2 million, respectively, during 2015.

Revenues

($ millions)	2016	2015	2014
Oil and natural gas sales	$ 882.1	$ 1,052.4	$ 1,849.3
Royalties	(159.4)	(168.0)	(323.1)
Oil and natural gas sales, net of royalties	$ 722.7	$ 884.4	$ 1,526.2

Oil and natural gas sales revenue for 2016 totaled $882.1 million, a decrease of 16% from $1,052.4 million in 2015. The decrease in revenue was a result of the continued decline in commodity prices compared to the prior year along with lower production due to non-core asset divestments and lower capital spending.

In 2015, oil and natural gas sales revenue decreased 43% to $1,052.4 million from $1,849.3 million in 2014 as a result of weak commodity prices, offset somewhat by growth in production volumes.

Royalties and Production Taxes

($ millions, except per BOE amounts)	2016	2015	2014
Royalties	$ 159.4	$ 168.0	$ 323.1
Per BOE	$ 4.67	$ 4.32	$ 8.58
Production taxes	$ 37.4	$ 50.9	$ 81.5
Per BOE	$ 1.10	$ 1.31	$ 2.17
Royalties and production taxes	$ 196.8	$ 218.9	$ 404.6
Per BOE	$ 5.77	$ 5.63	$ 10.75
Royalties and production taxes (% of oil and natural gas sales)	22%	21%	22%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. A large percentage of our production is from U.S. properties where royalty rates are generally not as sensitive to commodity price levels.

Royalties and production taxes were in line with our guidance for 2016, averaging 22% of oil and natural gas sales, before transportation. Royalties and production taxes decreased to $196.8 million in 2016 from $218.9 million in 2015 primarily due to lower production volumes, a decrease in realized crude oil and natural gas prices and a 1.5% rate reduction of production taxes in North Dakota. In 2015, royalties and production taxes decreased to $218.9 million from $404.6 million in the prior year primarily due to decreased realized crude oil and natural gas prices.

2017 Guidance

We expect royalty and production taxes in 2017 to average 23% of our oil and gas sales, before transportation. The increase compared to 2016 is due to the higher percentage of U.S. production as a result of additional capital spending and growth in our U.S. assets, as well as the divestment of our non-core Canadian properties during 2016.

Operating Expenses

($ millions, except per BOE amounts)	2016	2015	2014
Cash operating expenses	$ 249.0	$ 340.1	$ 347.3
Non-cash (gains)/losses(1)	(1.1)	0.4	1.3
Total operating expenses	$ 247.9	$ 340.5	$ 348.6
Per BOE	$ 7.27	$ 8.76	$ 9.26

(1) Non-cash (gains)/losses on fixed price electricity swaps.

Operating expenses during 2016 were $247.9 million or $7.27/BOE, beating our guidance of $7.50/BOE, largely due to higher than expected production volumes from our lower operating cost Marcellus properties during the fourth quarter. Compared to 2015, expenses decreased $92.6 million or 27% primarily due to successful cost saving initiatives, lower repairs and maintenance costs and the divestment of higher operating cost Canadian properties throughout 2016.

Operating expenses during 2015 were $340.5 million or $8.76/BOE compared to $348.6 million or $9.26/BOE in 2014. The improvement resulted mainly from cost savings and a continued increase in the U.S. weighting of production, which has lower operating metrics. This was offset in part by the impact of a weaker Canadian dollar on our U.S. dollar denominated operating expenses.

2017 Guidance

We expect operating expenses of $7.85/BOE in 2017. The modest increase from 2016 is a result of the expected increase in the corporate weighting of our liquids production.

Transportation Costs

($ millions, except per BOE amounts)	2016	2015	2014
Transportation costs	$ 107.1	$ 114.7	$ 101.2
Per BOE	$ 3.14	$ 2.95	$ 2.69

Transportation costs increased on a per BOE basis throughout the year to average $3.14/BOE in 2016, consistent with our guidance of $3.15/BOE and a 6% increase compared to $2.95/BOE in 2015. The increase was primarily due to the increased weighting of U.S. production with higher associated transportation costs and additional firm transportation commitments in the Marcellus, effective August 2016.

Transportation costs increased to $2.95/BOE in 2015 compared to $2.69/BOE in 2014 as a result of increasing U.S. production and costs associated with securing U.S. pipeline capacity. The impact of a weakening Canadian dollar on our U.S. transportation costs further increased our total reported expense.

2017 Guidance

We expect transportation costs of $3.90/BOE in 2017. The increase from 2016 is largely attributable to additional firm transportation commitments in the Marcellus that came into effect in August 2016 to deliver production to higher priced markets, lower production volumes due to the year-end 2016 divestment of non-operated North Dakota properties and a weaker Canadian dollar projected in 2017.

Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the “Pricing” section of this MD&A. Certain prior period amounts have been reclassified to conform with current period presentation.

Netbacks by Property Type	Year ended December 31, 2016 Crude Oil	Natural Gas	Total
Average Daily Production	47,206 BOE/day	275,538 Mcfe/day	93,125 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 37.86	$ 2.26	$ 25.88
Royalties and production taxes	(9.38)	(0.34)	(5.77)
Cash operating expenses	(10.29)	(0.72)	(7.31)
Transportation costs	(1.97)	(0.72)	(3.14)
Netback before hedging	$ 16.22	$ 0.48	$ 9.66
Cash gains/(losses)	4.34	0.05	2.36
Netback after hedging	$ 20.56	$ 0.53	$ 12.02
Netback before hedging ($ millions)	$ 280.4	$ 48.8	$ 329.2
Netback after hedging ($ millions)	$ 355.3	$ 54.2	$ 409.5

Netbacks by Property Type	Year ended December 31, 2015 Crude Oil	Natural Gas	Total
Average Daily Production	49,069 BOE/day	344,730 Mcfe/day	106,524 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 43.67	$ 2.15	$ 27.07
Royalties and production taxes	(10.54)	(0.24)	(5.63)
Cash operating expenses	(11.98)	(1.00)	(8.75)
Transportation costs	(1.84)	(0.65)	(2.95)
Netback before hedging	$ 19.31	$ 0.26	$ 9.74
Cash gains/(losses)	12.13	0.56	7.40
Netback after hedging	$ 31.44	$ 0.82	$ 17.14
Netback before hedging ($ millions)	$ 345.7	$ 33.0	$ 378.7
Netback after hedging ($ millions)	$ 562.9	$ 103.5	$ 666.4

Netbacks by Property Type	Year ended December 31, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	45,225 BOE/day	347,430 Mcfe/day	103,130 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 79.12	$ 4.28	$ 49.13
Royalties and production taxes	(19.78)	(0.61)	(10.75)
Cash operating expenses	(11.76)	(1.21)	(9.23)
Transportation costs	(1.89)	(0.55)	(2.69)
Netback before hedging	$ 45.69	$ 1.91	$ 26.46
Cash gains/(losses)	0.42	(0.03)	0.09
Netback after hedging	$ 46.11	$ 1.88	$ 26.55
Netback before hedging ($ millions)	$ 754.3	$ 241.9	$ 996.2
Netback after hedging ($ millions)	$ 761.3	$ 238.4	$ 999.7

(1) See “Non-GAAP Measures” in this MD&A.

Crude oil and natural gas netbacks per BOE after hedging were lower during 2016 compared to 2015 and 2014 primarily due to the weakness in commodity prices compared to both the prior years and lower realized hedging gains compared to 2015, partially offset by significant improvements in our operating costs. During 2016, our crude oil properties accounted for 85% and 87% of our netback before and after hedging, respectively.

General and Administrative Expenses

Total G&A expenses include cash G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans") and our stock option plan. See Note 10 and Note 14 to the Financial Statements for further details.

($ millions)	2016	2015	2014
Cash:			
G&A expense	$ 59.8	$ 81.3	$ 83.5
Share-based compensation expense	3.1	0.9	(1.2)
Non-Cash:			
Share-based compensation expense	27.0	19.6	13.4
Equity swap loss/(gain)	(3.6)	2.1	9.3
Total G&A expenses	$ 86.3	$ 103.9	$ 105.0

(Per BOE)	2016	2015	2014
Cash:			
G&A expense	$ 1.75	$ 2.09	$ 2.22
Share-based compensation expense	0.09	0.02	(0.03)
Non-Cash:			
Share-based compensation expense	0.80	0.51	0.36
Equity swap loss/(gain)	(0.11)	0.05	0.24
Total G&A expenses	$ 2.53	$ 2.67	$ 2.79

Cash G&A expenses in 2016 totaled $59.8 million ($1.75/BOE), outperforming our guidance of $1.80/BOE and a decrease of 26% from $81.3 million ($2.09/BOE) in 2015. The reduction from 2015 was primarily due to continued cost savings initiatives and the impact of ongoing staff reductions as we continue to divest of non-core assets and focus our business.

Our share price increased significantly during 2016, resulting in cash SBC expense of $3.1 million ($0.09/BOE) compared to an expense of $0.9 million ($0.02/BOE) in 2015. Following the settlement of the final grants of our cash-settled Restricted Share Unit ("RSU") plans during the year, the Director Share Unit ("DSU") plan is our only remaining LTI plan that we intend to settle in cash. We recorded non-cash SBC of $27.0 million ($0.80/BOE) in 2016 compared to $19.6 million ($0.51/BOE) in 2015. The increase in non-cash SBC was a result of an improvement in our performance multiplier based on our relative return in the Toronto Stock Exchange Oil and Gas Producers Index, along with additional grants issued under the treasury-settled LTI plans rather than the cash-settled plans.

Cash G&A expenses in 2015 were $81.3 million ($2.09/BOE) compared to $83.5 million ($2.22/BOE) in 2014. The decrease in cash G&A expenses compared to 2014 was primarily due to a 20% reduction in staff levels offset by one-time severance charges. Cash SBC expense was $0.9 million ($0.02/BOE) in 2015 compared to a recovery of $1.2 million ($0.03/BOE) in 2014. We recorded non-cash SBC of $19.6 million ($0.51/BOE) in 2015 compared to $13.4 million ($0.36/BOE) in 2014. The increase in non-cash SBC was a result of additional grants issued under the treasury-settled LTI plans.

We have hedged a portion of the outstanding cash-settled units under our LTI plans. We recorded a non-cash mark-to-market gain of $3.6 million on these hedges in 2016 (2015 - $2.1 million loss; 2014 – $9.3 million loss). As of December 31, 2016, we have 470,000 units hedged at a weighted average price of $16.89/share.

2017 Guidance

We expect our cash G&A expense to be approximately $1.80/BOE in 2017, consistent with 2016 despite lower expected production levels.

Interest Expense

($ millions)	2016	2015	2014
Interest on senior notes and bank facility	$ 45.4	$ 66.5	$ 62.2
Non-cash interest expense	-	-	0.6
Total interest expense	$ 45.4	$ 66.5	$ 62.8

Interest on our senior notes and bank credit facility in 2016 decreased 32% to $45.4 million compared to $66.5 million in 2015. The decrease in interest expense corresponds to a decrease in the aggregate principal amount of our outstanding senior notes following our repurchase of US$267 million of senior notes during the first half of 2016. The repurchase was funded by asset divestment proceeds and lower interest rate bank debt, which was repaid following our May 31, 2016 equity financing and the closing of our second quarter Canadian non-core asset divestment.

Interest expense increased to $66.5 million in 2015 from $62.8 million in 2014 due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments and an increased weighting of senior notes with higher interest rates compared to our bank credit facility following our US$200 million private placement in September 2014. Non-cash amounts recorded in 2014 consisted of unrealized losses on the interest component of our cross currency interest rate swap. See Note 11 to the Financial Statements for further details.

At December 31, 2016, approximately 97% of our debt consisted of fixed interest rate senior notes and approximately 3% was floating bank debt with weighted average interest rates of 5.0% and 2.6%, respectively.

Foreign Exchange

($ millions)	2016	2015	2014
Realized loss/(gain)	$ 0.1	$ (8.7)	$ 11.2
Unrealized loss/(gain)	(40.6)	182.6	45.9
Total foreign exchange loss/(gain)	$ (40.5)	$ 173.9	$ 57.1
US/CDN average exchange rate	1.32	1.28	1.10
US/CDN period end exchange rate	1.34	1.38	1.16

We recorded a net foreign exchange gain of $40.5 million in 2016 compared to losses of $173.9 million and $57.1 million in 2015 and 2014, respectively. Our foreign exchange exposure relates to fluctuations in the Canadian and U.S. dollar exchange rate.

In 2016, we recorded a realized loss of $0.1 million on day-to-day transactions denominated in foreign currencies, compared to a gain of $8.7 million and a loss of $11.2 million in 2015 and 2014, respectively. In 2015, realized foreign exchange included a gain of $39.9 million on the unwind of our US$175 million foreign exchange swaps and a gain of $3.3 million on the final settlement of our US$54 million senior notes and the corresponding foreign exchange swap. These gains were offset by cumulative losses of $39.2 million on our foreign exchange collars with final settlements in December 2015. In 2014, we recorded a $15.8 million loss on the final settlement of our cross currency interest rate swap and a gain of $0.7 million on our costless collars.

Unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing December 31, 2016 to December 31, 2015, the Canadian dollar strengthened relative to the U.S. dollar and we reduced our U.S. dollar denominated senior notes by 33%, resulting in an unrealized gain of $40.6 million. See Note 12 to the Financial Statements for further details.

Capital Investment

($ millions)	2016	2015	2014
Capital spending	$ 209.1	$ 493.4	$ 811.0
Office capital	1.5	4.5	7.0
Sub-total	210.6	497.9	818.0
Property and land acquisitions	$ 126.1	$ 9.5	$ 18.5
Property divestments	(670.4)	(286.6)	(203.6)
Sub-total	(544.3)	(277.1)	(185.1)
Total	$ (333.7)	$ 220.8	$ 632.9

2016

Capital spending in 2016 totaled $209.1 million, slightly below our revised guidance of $215 million due to some weather related deferrals of spending during the fourth quarter. We continued to focus capital on our core areas during 2016, spending $136.4 million on our North Dakota crude oil properties, $44.4 million on our Canadian crude oil waterflood properties and $24.3 million on our Marcellus natural gas assets. Through our capital program in 2016 we added 43 MMBOE of gross proved plus probable reserves, replacing 126% of our 2016 production, before accounting for acquisitions and divestments.

We recorded net divestment proceeds of $670.4 million in 2016. In Canada, we sold properties for combined proceeds of $281.0 million with production of approximately 8,500 BOE/day. Sold properties consisted mainly of natural gas assets, and included certain Deep Basin natural gas properties with production of 5,400 BOE/day and non-core properties in northwest Alberta with production of 2,300 BOE/day. Divestments resulted in a $35.6 million reduction to future asset retirement obligations. On December 30, 2016, we closed the sale of our non-operated assets in North Dakota with production of approximately 5,000 BOE/day for proceeds of $392.0 million, which was reported as restricted cash at December 31, 2016.

Property and land acquisitions in 2016 totaled $126.1 million, largely due to our acquisition of a Canadian waterflood property for a purchase price of $110.3 million, net of closing adjustments.

2015

Capital spending in 2015 totaled $493.4 million and included spending of $302.3 million on our North Dakota crude oil properties, $115.7 million on our Canadian crude oil properties, $32.2 million on our Marcellus assets and $40.4 million on our Deep Basin properties in Canada. Through our capital program in 2015 we added 42 MMBOE of gross proved plus probable reserves, replacing 108% of our 2015 production, before accounting for acquisitions and divestments.

During 2015, we recorded net divestment proceeds of $286.6 million. In Canada, we divested of assets for combined proceeds of $198.9 million with production of approximately 4,900 BOE/day including the sale of our Pembina waterflood assets and certain non-core shallow gas assets with production of 2,700 BOE/day. In the U.S., we divested of assets for combined proceeds of $87.7 million with production of approximately 1,250 BOE/day, including the sale of a portion of our non-operated North Dakota properties for proceeds of $80.4 million, and our operated Marcellus assets for proceeds of $3.5 million.

Property and land acquisitions in 2015 totaled $9.5 million and included minor acquisitions of leases and undeveloped land.

2014

Capital spending in 2014 totaled $811.0 million and included spending of $343.7 million on our North Dakota crude oil properties, $176.6 million on our Canadian crude oil properties, $158.8 million on our Marcellus assets and $124.5 million on our deep gas properties in Canada. Through our capital program in 2014 we added 75 MMBOE of gross proved plus probable reserves, replacing over 200% of our 2014 production.

Property divestments in 2014 totaled $203.6 million. In Canada we divested of natural gas properties in the Deep Basin area with production of approximately 3,100 BOE/day for proceeds of $91.0 million and recognized the remaining $65.8 million of proceeds on the 2013 sale of our undeveloped Montney acreage. During the first quarter, we sold our gross overriding royalty interest in the Jonah natural gas property in Wyoming with production of approximately 400 BOE/day for proceeds of $44.0 million, after closing adjustments. Property and land acquisitions in 2014 totaled $18.5 million and included several minor acquisitions across our core areas.

2017 Guidance

To re-position ourselves for growth in 2017, we are increasing our capital spending guidance to $450 million, more than twice our spending levels in 2016. We will continue to focus our spending on our core areas, with $330 million currently allocated to North Dakota crude oil properties, $60 million to Canadian waterflood crude oil properties and $60 million to the Marcellus natural gas properties.

Gain on Asset Sales and Note Repurchases

We recorded gains of $559.2 million on asset divestments during 2016, including a gain of $339.4 million on the fourth quarter sale of our non-operated North Dakota property. No gains were recorded on asset sales in 2015 or 2014. Under full cost accounting rules, divestments of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. Gains and losses are evaluated on a case by case basis for each asset sale, and future sales may or may not result in such treatment.

During the first half of 2016, we recorded a total gain of $19.3 million on the repurchase of US$267 million of outstanding senior notes at prices between 90% of par and par value.

Depletion, Depreciation and Accretion ("DD&A")

($ millions, except per BOE amounts)	2016	2015	2014
DD&A expense	$ 329.0	$ 508.2	$ 567.7
Per BOE	$ 9.65	$ 13.06	$ 15.08

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. DD&A has decreased from 2014 to 2016 primarily due to the quarterly asset impairments recorded during 2015 and 2016 under the U.S. GAAP full cost ceiling test methodology.

Impairments

PP&E

($ millions)	2016	2015	2014
Canada cost centre	$ 89.4	$ 286.7	$ —
U.S. cost centre	211.8	1,065.7	—
Total Impairments	$ 301.2	$ 1,352.4	$ —

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country cost centre basis using estimated after-tax future net cash flows discounted at 10% from proved reserves using SEC constant prices ("Standardized Measure"). SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. Standardized Measure is not related to our capital spending investment criteria and is not a fair value based measurement, but rather a prescribed accounting calculation. Under U.S. GAAP impairments are not reversed in future periods.

The trailing twelve month average crude oil and natural gas prices have decreased significantly in 2016 and 2015, resulting in non-cash impairments totaling $301.2 million and $1,352.4 million (before tax), respectively. We did not record any impairments on our oil and natural gas properties in 2014.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in our ceiling test at December 31, 2016, 2015 and 2014:

Year	WTI Crude Oil US$/bbl	Exchange Rate US/CDN	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
2016	$ 42.75	1.32	$ 52.26	$ 2.49	$ 2.17
2015	$ 50.28	1.27	$ 59.38	$ 2.58	$ 2.69
2014	$ 94.99	1.09	$ 94.84	$ 4.30	$ 4.60

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the next year, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, our capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. Although the twelve month average trailing commodity prices are below current levels, there is the potential for prices to decline further, impacting the ceiling value which could result in further non-cash impairments.

Goodwill

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We perform a qualitative assessment of goodwill by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value we perform quantitative impairment tests. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the consolidated statements of income/(loss) in the Financial Statements.

Our annual goodwill impairment assessments as at December 31, 2016 and 2015 indicated no impairment.

Asset Retirement Obligation

In connection with our operations, we incur abandonment and reclamation costs related to assets, such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on management's estimate of our net ownership interest, costs to abandon and reclaim and the timing of the costs to be incurred in future periods.

We have estimated the net present value of our asset retirement obligation to be $181.7 million at December 31, 2016, compared to $206.4 million at December 31, 2015. The decrease was largely due to the removal of $35.6 million of asset retirement obligations related to asset divestments during 2016. See Note 8 to the Financial Statements for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2016, we spent $8.4 million (2015 – $14.9 million) on our asset retirement obligations and we expect to spend approximately $13.1 million in 2017. The majority of our abandonment and reclamation costs are expected to be incurred between 2025 and 2055. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any abandonment and reclamation costs are anticipated to be funded out of cash flow and available credit facilities.

Income Taxes

($ millions)	2016	2015	2014
Current tax expense/(recovery)	$ (2.4)	$ (16.9)	$ 5.0
Deferred tax expense/(recovery)	(234.8)	(150.6)	132.8
Total tax expense/(recovery)	$ (237.2)	$ (167.5)	$ 137.8

Our current tax recovery mainly relates to a refund of U.S. Alternative Minimum Tax ("AMT") from a prior period.

The total tax recovery in 2016 was $237.2 million, compared to $167.5 million in 2015. The increased recovery in 2016 is due primarily to the removal of a portion of our valuation allowance recorded in 2015 due to higher future taxable income projected this year compared to 2015. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will be realized. We have considered available positive and negative evidence, including future taxable income and reversing existing temporary differences in making this assessment. This assessment is primarily the result of projecting future taxable income using December 30 benchmark forward prices for 2017, held constant and adjusted for other significant items affecting taxable income. Had we utilized forecast prices and costs to estimate future taxable income we expect that all of our deferred income tax assets would be realized and no valuation allowance would be required. Our overall deferred income tax asset, net of valuation allowance, is $733.4 million as at December 31, 2016 (2015 - $516.1 million).

In 2015, our total tax recovery was $167.5 million compared to an expense of $137.8 million in 2014. The recovery in 2015 was due primarily to lower income, which was impacted by a $1,352.4 million non-cash charge for asset impairments and a valuation allowance recorded against a portion of our deferred income tax asset.

Our estimated tax pools at December 31, 2016 are as follows:

Pool Type ($ millions)		**2016**
Canada		
Canadian development expenditures ("CDE")	$	63
Canadian exploration expenditures ("CEE")		236
Undepreciated capital costs ("UCC")		166
Non-capital losses and other credits		397
	$	862
U.S.		
Alternative minimum tax credit ("AMT")	$	112
Net operating losses		894
Depletable and depreciable assets		1,370
	$	2,376
Total tax pools and credits	$	3,238
Capital losses	$	1,224

Capital losses reflect the balance of unused capital losses available for carry-forward in Canada. These capital losses have an indefinite carry-forward period however can only be used to offset capital gains. We do not anticipate future capital gains that will allow us to utilize the capital losses. Therefore, a full valuation allowance has been applied to the deferred tax asset in respect of these capital losses.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2016, our senior debt to adjusted EBITDA ratio was 0.8x and our net debt to adjusted funds flow ratio was 1.2x, a significant improvement from 2.2x and 2.5x, respectively, at December 31, 2015. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

We strengthened our financial position significantly in 2016, reducing our net debt by 69% over the twelve month period. The overall reduction in debt was funded through proceeds from our May 2016 equity issuance and our ongoing non-core asset divestment program. On May 31, 2016, we completed an equity financing for 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million, net of issue costs). Asset divestments throughout 2016 resulted in aggregate divestment proceeds of $670.4 million. This additional liquidity was used to repay our bank credit facility, repurchase US$267 million of senior notes during the first half of 2016, at prices ranging from 90% of par to par value, and purchase our Canadian waterflood property in November for $110.3 million.

Net acquisition and divestment proceeds include $392.0 million from the sale of non-operated North Dakota properties, which were classified as restricted cash on the December 31, 2016 balance sheet. As of the date of this report, we expect to continue to hold these funds in escrow for a period of up to 180 days from the date of closing to facilitate possible future like-kind transactions in accordance with U.S. federal tax regulations.

Total debt, net of cash and restricted cash, at December 31, 2016 was $375.5 million compared to $1,216.2 million at December 31, 2015. Total debt was comprised of $23.2 million of bank indebtedness and $745.6 million of senior notes less $393.3 million in cash, including restricted cash. Our next scheduled senior notes repayment of US$22 million is due in June 2017 with remaining maturities extending to 2026.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 80% for 2016 compared to 128% in 2015. After adjusting for net acquisition and divestment proceeds, our funding surplus for the year ended December 31, 2016 was $603.8 million compared to $144.8 million in 2015. We expect to continue to pay monthly dividends to our shareholders of $0.01 per share, however, if economic conditions change we may make adjustments.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, decreased to $94.4 million at December 31, 2016 from $104.0 million at December 31, 2015. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. In addition, we have sufficient liquidity to meet our financial commitments for the near term, as disclosed under "Commitments" below.

During the fourth quarter, we completed a one year extension of our $800 million senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2019. There were no other amendments to the agreement terms or debt covenants. Drawn fees on our bank credit facility range between 150 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 170 basis points. The bank credit facility ranks equally with our senior unsecured covenant-based notes.

At December 31, 2016 we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at December 31, 2016:

Covenant Description		December 31, 2016
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.8x
Total debt to adjusted EBITDA	4.0x	0.8x
Total debt to capitalization	50%	23%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA[1]	3.0x – 3.5x	0.8x
Senior debt to consolidated present value of total proved reserves[2]	60%	28%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	20.4x

Definitions
"Senior Debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
"EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion and non-cash gains and losses. EBITDA is calculated on a trailing twelve month basis and is adjusted for material acquisitions and divestments. EBITDA for the three months and the trailing twelve months ended December 31, 2016 were $451.8 million and $921.0 million, respectively.
"Total Debt" is calculated as the sum of Senior Debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) Senior Debt to adjusted EBITDA maximum ratio for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.
(2) Maximum debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Counterparty Credit

OIL AND NATURAL GAS SALES COUNTERPARTIES

Our oil and natural gas receivables are with customers in the oil and gas industry and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. A credit review process is in place to assess and monitor our counterparties' creditworthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted, we obtain financial assurances such as letters of credit, parental guarantees or third party insurance to mitigate a portion of our credit risk. This process is utilized for both our oil and natural gas sales counterparties as well as our financial derivative counterparties.

FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the great majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. At December 31, 2016, we had $40.9 million of mark-to-market liabilities. The majority of our outstanding derivative contracts are with financial institutions which are members of our bank syndicate. All of our derivative counterparties are considered investment grade.

Dividends

($ millions, except per share amounts)	2016	2015	2014
Cash dividends	$ 35.4	$ 132.0	$ 199.3
Stock dividend plan	—	—	21.8
Total dividends to shareholders	$ 35.4	$ 132.0	$ 221.1
Per weighted average share (Basic)	$ 0.16	$ 0.64	$ 1.08

We reported total dividends of $35.4 million or $0.16 per share to our shareholders in 2016. During 2015 and 2014 we reported total dividends of $132.0 million or $0.64 per share and $221.1 million or $1.08 per share, respectively.

Cash dividends for 2016 represented approximately 12% of adjusted funds flow, compared to approximately 27% in 2015 and 23% in 2014. In September 2014, we elected to suspend our stock dividend plan, thereby eliminating any dilution resulting from issuing shares as part of our dividend plan.

To provide additional financial flexibility and to better balance adjusted funds flow with capital and dividends, we reduced our monthly dividend to $0.01 per share, effective with our April 2016 payment. During 2015, we reduced our monthly dividend twice, from $0.09 per share to $0.05 per share in April and to $0.03 per share in December.

The dividend is part of our strategy to create shareholder value; however, a sustained low price environment may impact our ability to pay dividends. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	2016	2015	2014
Share capital ($ millions)	$ 3,366.0	$ 3,133.5	$ 3,120.0
Common shares outstanding (thousands)	240,483	206,539	205,732
Weighted average shares outstanding – basic (thousands)	226,530	206,205	204,510
Weighted average shares outstanding – diluted (thousands)	231,293	206,205	207,424

On May 31, 2016, 33,350,000 common shares were issued at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million, net of issue costs).

During 2016, a total of 594,000 shares (2015 – 807,000; 2014 – 2,974,000) and $9.4 million of additional equity (2015 – $13.3 million; 2014 – $53.2 million) was issued pursuant to the treasury-settled LTI plans. For further details see Note 14 to the Financial Statements.

At February 23, 2017, we had 241,010,880 shares outstanding.

Commitments

As at December 31, 2016 we had the following minimum annual commitments:

		Minimum Annual Commitment Each Year					Total Committed
($ millions)	Total	2017	2018	2019	2020	2021	after 2021
Bank credit facility[1]	$ 23.2	$ —	$ —	$ 23.2	$ —	$ —	$ —
Senior notes[1]	746	30	29.5	59.5	109.6	109.6	407.9
Transportation commitments	293.6	31.9	29.1	24.6	22.8	19.5	165.7
Processing commitments	42.9	11.4	10.1	10.1	1.6	1.6	8.1
Drilling and completions	29.1	29.1	—	—	—	—	—
Office lease commitments	88.3	12.2	12.0	10.5	10.8	10.8	32.0
Sublease recoveries	(9.3)	(2.0)	(1.6)	(1.7)	(1.8)	(1.5)	(0.7)
Net office lease commitments	79.1	10.2	10.4	8.8	9.1	9.3	31.2
Total commitments[2][3]	$ 1,213.6	$ 112.2	$ 79.2	$ 126.3	$ 143.0	$ 140.0	$ 612.9

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

(3) US$ commitments have been converted to CDN$ using the December 31, 2016 foreign exchange rate of 1.3427.

In the Marcellus, we have firm sales contracts for up to 65,000 Mcf/day through 2026. We also have firm transportation agreements in place for approximately 66,000 Mcf/day, which expire between 2020 and 2033. This includes the agreement for additional interstate pipeline capacity on the Tennessee Gas Pipeline from our Marcellus producing region to downstream connections that became effective in August 2016. Under this agreement, we are committed to a US$0.63/Mcf demand toll for 30,000 Mcf/day of natural gas for 11 years, reducing to 15,000 Mcf/day for an additional 9 years, with a total estimated transportation commitment of $148.3 million extending to 2036. We have also entered into a binding contract for five years of firm transportation capacity for 30,000 Mcf/day on the PennEast pipeline project. This project is currently pending regulatory approval with an expected in-service date of 2018.

In Canada, we have various firm transportation agreements for approximately 2,700 BOE/day of our crude oil and natural gas liquids production in 2017, decreasing to approximately 1,800 BOE/day on average from 2018 to 2027. We also have firm natural gas transportation contracts in 2017 for approximately 99,000 Mcf/day. At December 31, 2016, we have firm natural gas liquids fractionation contracts for 825 BOE/day, which increase to 1,125 BOE/day from April 2017 through 2026.

Our Canadian office lease is committed to 2024 and our U.S. office lease expires in 2019. Annual costs of these lease commitments include rent and operating fees. Our office lease commitments are shown net of sublease agreements, which we entered into to reduce our obligations.

Our commitments, contingencies and guarantees are more fully described in Note 16 to the Financial Statements.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

	Year ended December 31, 2016			Year ended December 31, 2015		
(millions, except per unit amounts)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	13,089	25,264	38,353	15,165	26,474	41,639
Natural gas liquids (bbls/day)	1,408	3,495	4,903	1,997	2,766	4,763
Natural gas (Mcf/day)	79,057	220,157	299,214	136,924	223,809	360,733
Total average daily production (BOE/day)	27,673	65,452	93,125	39,983	66,541	106,524
Pricing[2]						
Crude oil (per bbl)	$ 39.91	$ 47.39	$ 44.84	$ 45.28	$ 50.23	$ 48.43
Natural gas liquids (per bbl)	27.52	10.36	15.29	29.41	9.88	18.06
Natural gas (per Mcf)	2.20	2.00	2.06	2.83	1.74	2.15
Capital Expenditures						
Capital spending	$ 44.4	$ 164.7	$ 209.1	$ 157.7	$ 335.7	$ 493.4
Acquisitions	114.4	11.7	126.1	3.6	5.9	9.5
Divestments	(281.0)	(389.4)	(670.4)	(198.9)	(87.7)	(286.6)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 269.2	$ 612.9	$ 882.1	$ 414.4	$ 638.0	$ 1052.4
Royalties	(35.8)	(123.6)	(159.4)	(44.8)	(123.2)	(168.0)
Production taxes	(2.5)	(34.9)	(37.4)	(5.5)	(45.4)	(50.9)
Cash operating expenses	(135.7)	(113.3)	(249.0)	(216.7)	(123.4)	(340.1)
Transportation costs	(14.0)	(93.1)	(107.1)	(22.6)	(92.1)	(114.7)
Netback before hedging	$ 81.2	$ 248.0	$ 329.2	$ 124.8	$ 253.9	$ 378.7
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 29.4	$ —	$ 29.4	$ (142.7)	$ —	$ (142.7)
General and administrative expense[4]	63.9	22.4	86.3	77.0	26.9	103.9
Current income tax expense/(recovery)	(0.7)	(1.7)	(2.4)	(0.8)	(16.1)	(16.9)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.
(4) Includes share-based compensation.

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2016	2015	2014
Oil and natural gas sales, net of royalties	$ 722.7	$ 884.4	$ 1,526.2
Net income/(loss)	397.4	(1,523.4)	299.1
Per share (Basic)	1.75	(7.39)	1.46
Per share (Diluted)	1.72	(7.39)	1.44
Adjusted funds flow[1]	305.6	493.1	859.0
Cash and stock dividends[2]	35.4	132.0	221.1
Per share (Basic)[2]	0.16	0.64	1.08
Total assets	2,638.9	2,581.2	4,031.5
Debt net of cash and restricted cash	375.5	1,216.2	1,134.9

(1) See "Non-GAAP Measures" section of this MD&A.
(2) Calculated based on dividends paid or payable. Cash and stock dividends to shareholders per share may not correspond to actual dividends as a result of using the annual weighted average shares outstanding.

2016 versus 2015

Net oil and natural gas sales were $722.7 million in 2016 compared to $884.4 million in 2015 due to weaker commodity prices and lower production volumes as a result of our asset divestments over the period.

We reported net income of $397.4 million in 2016 compared to a net loss of $1,523.4 million in 2015 primarily due to decreases of $1,051.3 million in non-cash asset impairment charges and $179.2 in DD&A recorded on our crude oil and natural gas assets and gains of $578.5 million realized in 2016 on our asset divestments and the prepayment of senior notes.

Adjusted funds flow decreased 38% to $305.6 million in 2016 from $493.1 million in 2015. The decrease was mainly a result of a $207.4 million decrease in realized gains on commodity hedges and a $161.7 million decline in net crude oil and gas sales over the period, offset by a combined decrease in cash operating costs, interest expense and cash G&A expenses of $133.7 million.

2015 versus 2014

In 2015, oil and natural gas sales, net income and adjusted funds flow decreased due to weak commodity prices, which were somewhat offset by production growth. A net loss was realized in 2015 primarily as a result of non-cash asset impairment charges of $1,352.4 million and a non-cash valuation allowance on our deferred income tax asset, along with lower oil and natural gas sales revenue and a $91.7 million decrease in total gains on commodity hedges. Adjusted funds flow benefited from realized cash gains on our commodity hedges, which increased to $287.7 million in 2015 compared to $3.5 million in 2014.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2016				
Fourth Quarter	$ 217.4	$ 840.3	$ 3.49	$ 3.43
Third Quarter	188.3	(100.7)	(0.42)	(0.42)
Second Quarter	174.3	(168.5)	(0.77)	(0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 722.7	$ 397.4	$ 1.75	$ 1.72
2015				
Fourth Quarter	$ 199.4	$ (625.0)	$ (3.03)	$ (3.03)
Third Quarter	228.3	(292.7)	(1.42)	(1.42)
Second Quarter	251.7	(312.5)	(1.52)	(1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 884.4	$ (1,523.4)	$ (7.39)	$ (7.39)

Oil and natural gas sales, net of royalties decreased in 2016 compared to 2015 due to a decline in commodity prices along with lower production due to non-core asset divestments. During 2015, the impact of weak commodity prices was somewhat offset by increasing production. Net income increased in 2016 largely due to a decrease in non-cash asset impairments on our crude oil and natural gas assets and gains realized on asset divestments. The net loss reported in 2015 was a result of non-cash asset impairments and valuation allowances on our deferred tax asset related to the decrease in the twelve month average commodity prices.

ENVIRONMENT

We strive to carry out our activities and operations in compliance with all applicable regulations and best industry practices. Our operations are subject to laws and regulations concerning pollution, protection of the environment and the handling of hazardous materials and waste. We set corporate targets and mandates to improve environmental performance and execute environmental initiatives to become more energy efficient and to reduce, reuse and recycle water and minimize waste.

We have a Safety and Social Responsibility Policy ("S&SR Policy"), which articulates our commitment to health and safety, environmental, stakeholder engagement, and regulatory compliance. Our Board of Directors and President & Chief Executive Officer are ultimately accountable for ensuring compliance with the S&SR Policy. The Safety & Social Responsibility Committee of our Board of Directors (the "S&SR Committee") is responsible for overseeing our S&SR performance, ensuring there are adequate systems in place to support ongoing compliance, and to plan and execute the Company's activities in a safe and socially responsible manner.

We have established processes and programs designed to evaluate and minimize health, safety, and environmental risks, and strive for continuous improvement in our S&SR performance. We also actively participate in industry recognized programs that support our sustainability goals.

The S&SR Policy articulates our commitment to protecting the health and safety of all persons and communities involved in, or affected by, our business activities, and articulates our commitment to the environment. It states we endeavor to: (i) proactively manage our impact on the environment and consider innovative improvement opportunities; (ii) work to reduce our environmental impact in the areas in which we operate; (iii) improve our water and land use practices; (iv) limit the waste we generate; (v) prevent and manage environmental releases; (vi) provide transparent disclosure; and (vii) provide resources and training to meet our environmental commitments. Our commitment to building meaningful and transparent relationships, engaging with our stakeholders, and adhering to responsible development of resources and regulatory compliance is also stated.

We intend to continue to improve energy efficiencies and proactively manage our greenhouse gas emissions in compliance with applicable government regulations, including regulations enacted in British Columbia, Alberta and at the federal level in Canada and the U.S.

There are inherent risks of spills and pipeline leaks at our operating sites and clean-up costs may be significant. However, we have active site inspection, corrosion risk management and asset integrity management programs to help minimize this risk. In addition, we carry environmental insurance to help mitigate the cost of releases should they occur.

Some of our operations use hydraulic fracturing techniques, which involves the injection of pressurized fluids, sand, and small amounts of additives into a well bore. Government and regulatory agencies continue to frame regulations related to this process. We believe we are in compliance with all current government regulations and industry best practices in the U.S. and Canada.

The S&SR Committee regularly reviews health, safety, environmental and regulatory updates, and risks. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and we have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations. However, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements.

Overall, we strive to operate in a socially responsible manner and believe our health, safety and environmental initiatives and performance confirm our ongoing commitment to environmental stewardship and the health and safety of our employees, contractors, and the public in the communities in which we operate.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with U.S. GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Oil and Natural Gas Properties and Reserves

Enerplus follows the full cost method of accounting for oil and natural gas properties. The process of estimating reserves is critical in determining several accounting estimates including the Company's depletion, ceiling test, valuation allowance and gain or loss calculations. Estimating reserves requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs and royalty burdens change. Reserves estimates impact net income through depletion, the determination of asset retirement obligation and the application of impairment tests. Revisions or changes in reserves estimates can have either a positive or a negative impact on net income.

Asset Impairment

Ceiling Test

Under the full cost method of accounting for Property, Plant and Equipment, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost centre ceiling, we are subject to a ceiling test write-down to the extent of such excess. These write-downs reduce net income and impact shareholders' equity in the period of occurrence and result in lower depletion expense in future periods. The volume and discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of our oil and natural gas properties could occur in the future. Under U.S. GAAP impairments are not reversed in future periods.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually at December 31. Goodwill and all other assets and liabilities are allocated to reporting units. To assess impairment, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit is higher than its related fair value then goodwill is written down to the reporting unit's implied fair value of goodwill. The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates.

Income Taxes

Management makes certain estimates in calculating deferred tax assets and liabilities, as well as income tax expense. These estimates often involve judgment regarding differences in the timing and recognition of revenue and expense for tax and financial reporting purposes as well as the tax basis of our assets and liabilities at the balance sheet date before tax returns are completed. Additionally, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. We must record a valuation allowance against a deferred tax asset where all or a portion of that asset is not expected to be realized. In evaluating whether a valuation allowance should be applied, we consider evidence such as future taxable income, among other factors, both positive and negative. That determination involves numerous judgments and assumptions and includes estimating factors such as commodity prices, production and other operating conditions. If any of those factors, assumptions or judgments changes, the deferred tax asset could change, and in particular decrease in a period where we determine it is more likely than not that the asset will not be realized. Alternatively, a valuation allowance may be reversed where it is determined it is more likely than not that the asset will be realized.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and depleted over its useful life. There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserves estimates, costs and technology.

Business Combinations

Management makes various assumptions in determining the fair value of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we, and independent evaluators, estimate oil and gas reserves and future prices of crude oil and natural gas.

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 2(o) in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2016.

RISK FACTORS AND RISK MANAGEMENT

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, natural gas liquids, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic supply and demand of crude oil, natural gas and natural gas liquids and economic conditions, including currency fluctuations, weather conditions, the ability to export oil and liquefied natural gas and natural gas liquids from North America and the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American crude oil, natural gas and natural gas liquids, political stability, transportation facilities, availability of processing, fractionation and refining facilities, the effect of world-wide energy conservation and greenhouse gas reduction measures, the price and availability of alternative fuels and existing and proposed changes to government regulations.

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

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and crude oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. At February 23, 2017, approximately 63% of our 2017 forecasted net crude oil production is hedged and approximately 23% of our 2017 forecasted net natural gas production is hedged at price levels disclosed in the "Price Risk Management" section above. We have also hedged approximately 44% and 14%, respectively, of our forecasted 2017 net crude oil production in 2018 and 2019. Refer to the "Price Risk Management" section for further details on our price risk management program.

Risk of Increased Capital or Operating Costs

Higher capital or operating costs associated with our operations will directly impact our capital efficiencies and cash flow. Capital costs of completions, specifically the costs of proppant, and operating costs such as electricity, chemicals, supplies, energy services and labour costs, are a few of the costs that are susceptible to material fluctuation. Although we have a portion of our 2017 capital and operating costs protected with existing agreements, changing regulatory conditions, such as those in the U.S. requiring that certain raw materials be sourced from the U.S., may result in higher than expected supply costs.

Access to Field Services

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Activity levels in each area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services into 2017, access to field services and supplies in other areas of our business will continue to be subject to market availability.

Risk of Curtailed or Shut-in Production

Should we be required to curtail or shut-in production as a result of low commodity prices, environmental regulation or third party operational practices, it could result in a reduction to cash flow and production levels, and may result in additional operating and capital costs for the well to achieve prior production levels. In addition, curtailments or shut-ins may cause damage to the reservoir and may prevent us from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. With regard to curtailment, although regional pipeline capacity has increased over the past several years, sales gas infrastructure capacity in northeastern Pennsylvania remains constrained relative to the amount of natural gas that can be produced. Combined with the ongoing volatility in natural gas prices, this may result in continued discounted prices and an ongoing risk of price-related production curtailments.

Debt covenants may be exceeded with no ability to negotiate covenant relief

Declines in oil and natural gas prices may result in a significant reduction in earnings or cash flow, which could lead us to increase drawn amounts under the bank credit facility to carry out our operations and fulfill our 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 a breach of our debt covenants. If a breach occurs, there is a risk that we may not be able to negotiate covenant relief with one or more of our lenders. Failure to comply with debt covenants or negotiate relief may result in our indebtedness under the bank credit facility and senior note agreements becoming immediately due and payable, which may have a material adverse effect on our operations and financial condition.

Our most restrictive debt covenant is a maximum senior debt to adjusted EBITDA ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2016, our senior debt to adjusted EBITDA ratio was 0.8x. We routinely review our compliance with covenants based on actual and forecasted results, and have the ability to adjust our capital spending levels and dividends or pursue asset divestments and equity issuances to comply with our covenants.

See the “Liquidity and Capital Resources” section for further information.

Counterparty and Joint Venture Credit Exposure

We are subject to the risk that the counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements as a result of liquidity requirements or insolvency. Low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure of our counterparties to perform their financial or operational obligations may adversely affect our operations and financial position. In addition to the usual delays in payment by purchasers of crude oil and natural gas, payments may also be delayed by, among other things: (i) capital or liquidity constraints experienced by our counterparties, including restrictions imposed by lenders; (ii) accounting delays or adjustments for prior periods; (iii) delays in the sale or delivery of products or delays in the connection of wells to a gathering system; (iv) weather related delays, such as freeze-offs, flooding and premature thawing; (v) blow-outs or other accidents; or (vi) recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for these expenses. Any of these delays could reduce the amount of our cash flow and the payment of cash dividends to our shareholders in a given period and expose us to additional third party credit risks.

A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This includes reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we attempt to obtain financial assurances such as letters of credit, parental guarantees, or third party insurance to mitigate our counterparty risk. In addition, we monitor our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn bank facilities and, where possible, take our production in kind rather than relying on third party operators. In certain instances, we may be able to aggregate all amounts owing to each other and settle with a single net amount.

See the “Liquidity and Capital Resources” section for further information.

Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of our oil and gas reserves and resources. Geological and operational risks along with product price forecasts can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower crude oil, natural gas liquids, and natural gas prices along with lower development capital spending associated with certain projects may increase the risk of write-downs for our oil and gas property investments. Changes in reporting methodology as well as regulatory practices can result in reserves or resources write-downs.

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as evaluating or auditing the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with NI 51-101 standards. For U.S. GAAP accounting purposes, our proved reserves are estimated to be technically the same as our proved reserves prepared under NI 51-101 and have been adjusted for the effects of SEC constant prices. Independent reserves evaluations have been conducted on approximately 86% of the total proved plus probable net present value (discounted at 10% and using NI 51-101 standards) of our reserves at December 31, 2016. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 48% of our Canadian reserves and reviewed the internal evaluation completed by Enerplus on the remaining portion. McDaniel also evaluated 100% of the reserves associated with our U.S. tight oil assets. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated 100% of our U.S. Marcellus shale gas assets.

The evaluations of best estimate development pending contingent resources associated with a portion of our Canadian waterflood properties and our Fort Berthold assets were conducted by Enerplus' qualified reserves evaluators and audited by McDaniel. NSAI evaluated our Marcellus shale gas best estimate development pending contingent resources.

The Reserves Committee and the Board of Directors has reviewed and approved the reserves and resources reports of the independent evaluators.

Risk of Impairment of 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 reporting date. The amount by which the net capitalized costs exceed the discounted value will be charged to net income.

Under U.S. GAAP, the net deferred tax assets is limited to the estimate of future taxable income resulting from existing properties. We estimate our future taxable income based on before-tax future net revenue from proved reserves, undiscounted, using benchmark 2017 forward prices on December 30, 2016, held constant 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, however these amounts can be reversed in future periods if future taxable income increases.

In 2016 we reported a non-cash impairment of $301.2 million on our crude oil and natural gas assets, compared to $1,352.4 million in 2015, and a non-cash recovery of $234.8 million due in part to the reversal of a portion of the valuation allowance recorded on our deferred tax asset in 2015. While these amounts do not affect cash flow, the volatility in earnings may be viewed unfavourably in the market. There is risk of further impairment on our oil and gas properties and deferred tax asset if commodity prices weaken during 2017. Additional write-downs may lead to a breach of our Total Debt to Capitalization covenant under the bank credit facility, and we may not be able to renegotiate our covenants.

Access to Transportation and Processing Capacity

Market access for crude oil, NGLs and natural gas production in Canada and the U.S. is dependent on our ability to obtain transportation capacity on third party pipelines and rail as well as access to processing facilities. Newer resource plays, such as the North Dakota Bakken and the Marcellus shale gas, generally experience a sharp production increase in the area which could exceed the existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. Our assets are concentrated in specific regions with varying levels of government that could limit or ban the shipping of commodities by truck, pipeline or rail. Special interest groups could also oppose infrastructure development resulting in a delay or even the cancellation of the required infrastructure, further impeding our ability to produce and market our products. Additionally, the transportation of crude oil by rail may come under closer scrutiny by government regulatory agencies in Canada and the U.S.. As a result, there may be incremental costs associated with transporting crude oil by rail, and there is a risk that access to rail transport may be constrained, depending upon any changes made to existing rail transport regulations.

We continuously monitor this risk for both the short and longer term through dialogue and review with the third party pipelines and other market participants. Where available and commercially appropriate, given the production profile and commodity, we attempt to mitigate transportation and processing risk by contracting for firm pipeline or processing capacity or using other means of transportation, including truck or selling to third parties that have access to rail capacity.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as most of our senior notes are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements. We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted when the Canadian dollar weakens relative to the U.S. dollar. However, our U.S. capital spending, transportation and operating costs, interest expense and debt repayments are negatively impacted with a weak Canadian dollar.

Currently, we do not have any foreign exchange contracts in place to hedge our foreign exchange exposure. However, we continue to monitor fluctuations in foreign exchange and the impact on our operations.

Ability to Divest Properties

Recent regulatory changes in Alberta and Saskatchewan have increased the minimum corporate liability rating required of purchasers of crude oil and natural gas properties. As a result, the potential number of parties able to acquire our non-core assets has been reduced, we may not be able to obtain full value for such assets, or transactions may involve greater risk and complexity.

Anticipated Benefits of Acquisitions or Divestments

From time to time, we may acquire additional crude 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 our ability to realize the anticipated growth opportunities from combining and integrating the acquired assets and properties into our existing business. These activities will require the dedication of substantial management effort, time, 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 risk factors specified in this MD&A relating to the crude oil and natural gas business and our operations, reserves and resources apply equally to future properties or assets that we may acquire. We generally conduct due diligence in connection with acquisitions, but there is no assurance that we will identify all the potential risks and liabilities related to such properties.

When acquiring assets, we are subject to inherent risks associated with predicting the future performance of those assets. We may make certain estimates and assumptions respecting the characteristics of the assets we acquire, that may not be realized over time. As such, assets acquired may not possess the value we attribute to them, which could adversely impact our future cash flows. To the extent that we make acquisitions with higher growth potential, the higher risks often associated may result in increased chances that actual results may vary from our 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 our engineers, and these initial assessments may differ significantly from our subsequent assessments.

Certain acquisitions, and in particular acquisitions of higher risk/higher growth assets and the development of those acquired assets, may require capital expenditures and we may not receive cash flow from operations from these acquisitions for several years, or in amounts less than anticipated. Accordingly, the timing and amount of capital expenditures may adversely affect our cash flow.

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

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through issuance of equity and debt in past years. Continued access to capital is dependent on our ability to optimize our existing assets and to demonstrate the advantages of the acquisition or development program that we are financing at the time, as well as investors' view of the oil and gas industry overall. We may not be able to access the capital markets in the future on terms favorable to us, or at all. Our continued access to capital markets is dependent on corporate performance and investor perception of future performance (both corporately and for the oil and gas sector in general).

We are required to assess our "foreign private issuer" status under U.S. securities laws on an annual basis. If we were to lose our status as a "foreign private issuer" under U.S. securities laws, we may have restricted access to capital markets for a period of time until the required approvals are in place from the U.S. Securities and Exchange Commission.

Regulatory Risk & Greenhouse Gas Emissions

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we operate under federal, provincial, state and municipal legislation and regulation that govern such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income, and the exportation of crude oil, natural gas and other products. We may be required to apply for regulatory approvals in the ordinary course of business. To the extent that we fail to comply with applicable government regulations or regulatory approvals, we may be subject to compliance and enforcement actions that are either remedial or punitive to deter future noncompliance. Such actions include fines or fees, notices of noncompliance, warnings, orders, administrative sanctions, and prosecution.

Government regulations may be changed from time to time in response to economic or political conditions, including the election of new state, provincial or federal leaders. Additionally, our entry into new jurisdictions or adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. Canadian and U.S. governments have enhanced their oversight and reporting obligations associated with fracturing procedures and increased their scrutiny of the usage and disposal of chemicals and water used in fracturing procedures. 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 ("VOC"), and methane gas emissions. Specifically, the Province of Alberta instituted the Climate Leadership Act in 2016, which, starting in 2023, sets a carbon tax of $30 per tonne of carbon dioxide equivalent emissions that occur from our Alberta operations. The Province of Alberta has also established a reduction goal of 45% for methane gas emissions for our Alberta operations by 2025. The Act will likely increase electrical use costs for our Alberta operations as a carbon tax for electrical use comes into effect in 2017.

The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations could negatively impact the development of oil and gas properties and assets, reduce demand for crude oil and natural gas or impose increased costs on oil and gas companies including taxes, fees or other penalties.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas by participating in industry organizations, conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results.

Specifically, with respect to regulations for the reduction of greenhouse gas emissions, the Canadian federal government continues to seek alignment for the regulations to be issued in Canada with those of the U.S.. Accordingly, while we continue to prepare to meet the potential requirements, the actual cost impact and its materiality to our business remains uncertain on a federal level.

Risk of Public Opposition and Activism

The oil and natural gas industry elicits concerns over climate change, as well as general public opposition to the industry. As a result, industry participants such as Enerplus may be subject to increased public activism, as well as extensive environmental regulation. Activist activity may result in increased costs due to delays or damage.

The expansion of our business activities, both geographically and with a new focus on exploration, may draw increased attention from shareholder activists who oppose our strategy, which could have an adverse effect on market value. Our ongoing participation in the Canadian and U.S. capital markets may expose us to greater risk of class action lawsuits related to securities law, title, contractual and environmental matters.

Health, Safety and Environmental Risk

Health, safety and environmental risks impact our workforce and operating costs and result in the enhancement of our business practices and standards. There may be risks associated with hydraulic fracturing including the risk of induced seismicity with the injection of fluid into any reservoir. We expect regulatory frameworks will be amended or continue to emerge in this regard. Although Enerplus proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements surrounding hydraulic fracturing. The impact of such changes on our business could increase our cost of compliance and the risk of litigation and environmental liability.

We have an S&SR department that develops standards and systems to manage health, safety and environmental risks, and regulatory compliance. The S&SR Committee of our Board of Directors is responsible for overseeing the organization's health, safety and environmental performance and ensuring there are adequate systems in place to support ongoing compliance, and to plan and execute activities in a safe and socially responsible manner. We have insurance to cover a portion of our property losses, liability and business interruption. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations.

Changes in Income Tax and Other Laws

Income tax, other laws or government incentive programs relating to the oil and gas industry may be changed in a manner that adversely affects us or our security holders. Canadian, U.S. and foreign tax authorities may interpret applicable tax laws, tax treaties or administrative positions differently than we do or may disagree with how we calculate our income for tax purposes in a manner which is detrimental to us and our security holders.

We monitor developments with respect to pending legal changes and work with the industry and professional groups to ensure that our concerns with any changes are made known to various government agencies. We obtain confirmation from independent legal counsel and advisors with respect to the interpretation and reporting of material transactions.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new land, reserves and/or resources and developing existing reserves and resources. Acquisitions of oil and gas assets will depend on our assessment of value at the time of acquisition and ability to secure the acquisitions generally through a competitive bid process.

Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions and our annual capital development budget are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.

Title Defects or Litigation

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

Although we conduct title reviews prior to the purchase of assets these reviews do not guarantee that an unforeseen defect in the chain of title will not arise. We maintain good working relationships with our industry partners; however, disputes may arise from time to time with respect to ownership of rights of certain properties or resources.

Interest Rate Exposure

We have exposure to movements in interest rates and credit markets as changing interest rates affect our borrowing costs and value of investments such as our shares as well as other equity investments.

We monitor the interest rate forward market and have fixed the interest rate on approximately 97% of our debt through our senior notes.

Cyber Security Risks

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

ADJUSTED FUNDS FLOW SENSITIVITY

The sensitivities below reflect all commodity contracts listed in Note 15 to the Financial Statements and are based on 2017 guidance price levels. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table		**Estimated Effect on 2017 Adjusted Funds Flow per Share[(1)]**
Change of $0.50 per Mcf in the price of NYMEX natural gas	$	0.21
Change of US$5.00 per barrel in the price of WTI crude oil	$	0.25
Change of 1,000 BOE/day in production	$	0.03
Change of $0.01 in the US/CDN exchange rate	$	0.02
Change of 1% in interest rate	$	0.03

(1) Assumes 240.5 million weighted average shares outstanding.

2017 GUIDANCE

A summary of our previously released 2017 guidance is below, including our updated Bakken crude oil differential of US$4.50/bbl below WTI (from $6.00/bbl previously). This guidance includes the impact of the 2016 fourth quarter non-operated North Dakota sale and Canadian waterflood purchase. No additional potential acquisitions or divestments have been included. This guidance is based on a WTI crude oil price of US$55.00/bbl, NYMEX natural gas price of US$3.00/Mcf, AECO natural gas price of $2.75/GJ and a US/CDN exchange rate of 1.35.

Summary of 2017 Expectations	**Target**
Capital spending	$450 million
Average annual production	86,000 – 90,000 BOE/day
Fourth quarter average production	92,000 – 97,000 BOE/day
Average annual crude oil and natural gas liquids production	40,000 – 43,000 bbls/day
Fourth quarter average annual crude oil and natural gas liquids production	45,000 – 50,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	23%
Operating expenses	$7.85/BOE
Transportation costs	$3.90/BOE
Cash G&A expenses	$1.80/BOE

2017 Differential/Basis Outlook[(1)]	
U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.50)/bbl
Marcellus basis (compared to NYMEX natural gas)	US$(0.90)/Mcf

(1) Before field transportation costs

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and therefore may not be comparable with the calculation of similar measures by other entities:

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback	**Year ended December 31,**		
($ millions)	**2016**	**2015**	**2014**
Oil and natural gas sales, net of royalties	$ 722.7	$ 884.4	$ 1,526.2
Less:			
Production taxes	(37.4)	(50.9)	(81.5)
Cash operating expenses[(1)]	(249.0)	(340.1)	(347.3)
Transportation costs	(107.1)	(114.7)	(101.2)
Netback before hedging	$ 329.2	$ 378.7	$ 996.2
Cash gains/(losses) on derivative instruments	80.3	287.7	3.5
Netback after hedging	$ 409.5	$ 666.4	$ 999.7

(1) Operating costs adjusted to exclude non-cash gains on fixed price electricity swaps of $1.1 million in 2016 and non-cash losses of $0.4 million in 2015 and $1.3 million in 2014.

"Adjusted funds flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. Adjusted funds flow is calculated as net cash from operating activities before asset retirement obligation expenditures and changes in non-cash operating working capital.

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	**Year ended December 31,**		
($ millions)	**2016**	**2015**	**2014**
Cash flow from operating activities	$ 312.3	$ 465.3	$ 787.2
Asset retirement obligation expenditures	8.4	14.9	19.4
Changes in non-cash operating working capital	(15.1)	12.9	52.4
Adjusted funds flow	$ 305.6	$ 493.1	$ 859.0

"Net debt to adjusted funds flow ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as total debt net of cash, including restricted cash, divided by a trailing 12 months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

"Adjusted payout ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends plus capital and office expenditures divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Year ended December 31,**		
($ millions)	**2016**	**2015**	**2014**
Dividends[(1)]	$ 35.4	$ 132.0	$ 199.3
Capital and office expenditures	210.6	497.9	818.0
Sub-total	$ 246.0	$ 629.9	$ 1,017.3
Adjusted funds flow	$ 305.6	$ 493.1	$ 859.0
Adjusted payout ratio (%)	80%	128%	118%

(1) Cash dividends exclude stock dividend plan proceeds in 2014. The stock dividend plan was suspended during 2014.

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes.

Reconciliation of Net Income to Adjusted EBITDA[(1)]

($ millions)	December 31, 2016
Net income/(loss)	$ 397.4
Add:	
Interest expense	45.4
Current and deferred tax expense/(recovery)	(237.2)
DD&A and asset impairment charges	630.1
Other non-cash charges[(2)]	91.5
Sub-total	$ 927.2
Adjustment for material acquisitions and divestments[(3)]	(6.2)
Adjusted EBITDA	$ 921.0

(1) Adjusted EBITDA is calculated based on the trailing four quarters.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC, and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than $50 million as if that acquisition or divestment had been made at the beginning of the period.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "debt net of cash", "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "maximum debt to consolidated present value of total proved reserves" and "adjusted EBITDA to interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal controls over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2016, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2016 and ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2017 total and fourth quarter 2017 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2017 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2017 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes and to negotiate relief if required; our future acquisitions and dispositions, expecting timing thereof and use of *proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.*

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our 2017 guidance contained in this MD&A is based on the following: a WTI price of US$55.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.75/GJ and a USD/CDN exchange rate of 1.35. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves 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 including, without limitation: continued low commodity prices environment or further decline of commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF and Form 40-F as at December 31, 2016).

The purpose of our adjusted funds flow sensitivity is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes. The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

EXHIBIT 99.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use of our reports dated February 24, 2017, relating to the consolidated financial statements of Enerplus Corporation and its subsidiaries (“Enerplus”) and the effectiveness of Enerplus’ internal control over financial reporting appearing in this Annual Report on Form 40-F of Enerplus Corporation for the year ended December 31, 2016.

/s/ DELOITTE LLP
Chartered Professional Accountants

Calgary, Canada
February 24, 2017

EXHIBIT 99.5

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of our name in the Annual Report on Form 40-F (the "Annual Report") of Enerplus Corporation (the "Registrant"). We hereby further consent to the inclusion in the Annual Report of the Registrant's Annual Information Form dated February 24, 2017 for the year ended December 31, 2016, which document makes reference to our firm and our reports dated January 25, 2017, evaluating the Registrant's oil, natural gas and natural gas liquids interests effective December 31, 2016.

Calgary, Alberta, Canada February 24, 2017	MCDANIEL & ASSOCIATES CONSULTANTS LTD.
	/s/ P.A. WELCH
	P.A. Welch, P.Eng. President & Managing Director

EXHIBIT 99.6

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of our name in the Annual Report on Form 40-F (the “Annual Report”) of Enerplus Corporation (the “Registrant”). We hereby further consent to the inclusion in the Annual Report of the Registrant’s Annual Information Form dated February 24, 2017 for the year ended December 31, 2016 which document makes reference to our firm and our report dated February 10, 2017 evaluating the Registrant’s shale gas and contingent resources interests effective December 31, 2016.

Dallas, Texas, U.S.A.
February 24, 2017

NETHERLAND, SEWELL &
ASSOCIATES, INC.

/s/ C.H. (SCOTT) REES III

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

EXHIBIT 99.7

CERTIFICATION

I, Ian C. Dundas, certify that:

1. I have reviewed this Annual Report on Form 40-F of Enerplus Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 24, 2017

/s/ IAN C. DUNDAS
Ian C. Dundas
President and Chief Executive Officer
of Enerplus Corporation

EXHIBIT 99.8

CERTIFICATION

I, Jodine J. Jenson Labrie, certify that:

1. I have reviewed this Annual Report on Form 40-F of Enerplus Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 24, 2017

/s/ JODINE J. JENSON LABRIE

Jodine J. Jenson Labrie
Senior Vice President and
Chief Financial Officer of Enerplus Corporation

EXHIBIT 99.9

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Enerplus Corporation (the "Corporation") on Form 40-F for the fiscal year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ian C. Dundas, President and Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

/s/ Ian C. Dundas

Ian C. Dundas
President and Chief Executive Officer
of Enerplus Corporation

February 24, 2017

The foregoing certification shall not be deemed "filed" for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the registrant specifically incorporates it by reference.

EXHIBIT 99.10

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Enerplus Corporation (the "Corporation") on Form 40-F for the fiscal year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jodine J. Jenson Labrie, Senior Vice President and Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

/s/ Jodine J. Jenson Labrie

Jodine J. Jenson Labrie
Senior Vice President and
Chief Financial Officer of Enerplus Corporation

February 24, 2017

The foregoing certification shall not be deemed "filed" for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the registrant specifically incorporates it by reference.

EXHIBIT 99.11

CODE OF BUSINESS CONDUCT

The Code of Business Conduct is our guide to ethical and lawful conduct in our daily business. It requires all of us, from members of our board of directors to new hires, to adhere to a level of ethical business conduct well in excess of the legal minimum. Our compliance with both the letter and spirit of the Code of Business Conduct is essential to protecting Enerplus' business and reputation.

INTRODUCTION

Enerplus' Commitment

Enerplus Corporation and all of its affiliates ("Enerplus" or the "Corporation") are committed to maintaining the highest of business standards in our operations, wherever they may be. We recognize the importance of credibility, integrity, and trust to our success as a business.

Purpose and Applicability of the Code

This Code of Business Conduct summarizes a number of Enerplus policies for appropriate behaviour and applies to all employees, consultants, officers and directors of Enerplus (hereinafter, "Employees"). Accordingly, each of us must comply with the terms of this Code. The Code will help us meet our business practice standards and comply with applicable laws and regulations. It is essential that this Code of Business Conduct be observed. The Code is very important to protecting Enerplus' business and reputation.

The Code of Business Conduct is a general guideline for making certain that:

- A work environment is maintained that promotes the dignity and self-respect of each Employee.
- All Employees are aware of and fully observe the laws and regulations that impact their business activities.
- A standard of behaviour is in place that reflects the values and integrity of Enerplus and its Employees.
- Enerplus is protected from financial loss and legal liability.

This Code of Business Conduct does not replace any other published rules and policies of Enerplus, including other guidelines and personal conduct policies. All Enerplus policies and standards are subject to this Code. While this Code of Business Conduct provides guidance and explains what is considered unacceptable behaviour, the Code of Business Conduct does not describe every specific act that is unacceptable. If a specific act is missing from the Code, it does not mean that act is acceptable or condoned. Ultimately, we must rely on our judgment about the right thing to do in order to maintain our personal and corporate integrity.

The Code is to be used as a guide for appropriate conduct and to prevent improper conduct. Enerplus will not tolerate any conduct that is unlawful or damaging to Enerplus' reputation.

Employee Responsibilities

All Employees are responsible for reading this entire Code of Business Conduct and ensuring their conduct is consistent with both the letter and the spirit of Enerplus' business practices.

This Code will help Employees deal with specific situations. In some cases, a situation may be so complex or circumstances so unique that additional guidance is needed. If such a situation occurs and is not included in this Code, it is each Employee's duty to contact his/her supervisor or the People and Culture Department immediately. If necessary, the People and Culture Department may refer the matter to the Legal Department for further advice.

This Code and any detailed Enerplus policy statements and procedures will be updated from time to time. All Employees are required to stay informed of any updates and to comply with all requirements.

<u>Management Responsibilities</u>

Managers must exhibit the highest standards of corporate responsibility and business conduct and create a work atmosphere that supports our corporate values and policies, including this Code. It is the duty of each member of management to take into account an Employee's willingness and commitment to comply with this Code when making promotion and other employment decisions.

<u>Compliance Requirements</u>

Employees must work honestly and in good faith. Employment with Enerplus depends upon an Employee's ability and willingness to comply with this Code. Adherence to these standards carries the highest priority. All Employees are required to acknowledge compliance when they are hired and again on an annual basis.

GLOBAL BUSINESS CONDUCT GUIDELINES

Our Employees

<u>Discrimination, Bullying and Workplace Harassment</u>

Employees are forbidden to discriminate against, bully or harass other Employees, in keeping with our Harassment Policy. No Employee is permitted to act in a way that is considered or could be considered illegal or harassing.

It is the responsibility of each member of management to be aware of any behaviour or conduct that could be considered workplace harassment, bullying or discrimination. Management also is required to enforce these policies and immediately contact the People and Culture Department regarding any situation that could be considered workplace harassment, bullying or discrimination.

It is the responsibility of each Employee to maintain a work environment free of discrimination, bullying and harassment and to report any situation that the Employee believes may be workplace harassment, bullying or discrimination to his/her supervisor, department head or the People and Culture Department.

<u>Employment of Family Members</u>

Enerplus allows an Employee's spouse, parents, children, and other family members to work for Enerplus, both during and after the employee's career with Enerplus, provided the employment is in Enerplus' best interest. Family relationships, however, will not be considered in hiring decisions. All Enerplus hiring decisions will be made strictly on the basis of individual qualifications. To avoid the possibility or appearance of preferential treatment, Enerplus will not have one family member placed in a position of influence over another family member.

<u>Workplace Health and Safety</u>

The health and safety of our personnel and the safe operation of our facilities are principal objectives of Enerplus. We are committed to providing safe and healthy places of employment and will follow operating practices that eliminate or minimize exposure to hazardous or unhealthy conditions. The success of our health and safety efforts depends upon the cooperation, support, and active involvement of all Enerplus personnel. Each Employee is responsible for working safely and complying with all safety rules and protocols at all times. We are committed to maintaining a safe and secure work environment. Threats, intimidation, harassment, assaults, and acts of violence are unacceptable and will not be tolerated.

Employees should refer to the Safety & Social Responsibility section of the Enerplus website for our Safety & Social Responsibility Policy and minimum safety standards. Questions or concerns should be reported immediately to a supervisor, the Safety & Social Responsibility Department or the People and Culture Department.

<u>Prohibited Items</u>

The use, sale, possession or distribution of illegal drugs, or the improper use of alcohol or prescription drugs, by Employees is strictly forbidden while on Enerplus premises, in Enerplus vehicles, or while conducting Enerplus business on or off Enerplus premises. The use of alcohol is prohibited to the extent that it has a detrimental effect on job performance, safety, or efficiency while conducting Enerplus business on or off Enerplus premises. The approval of an Enerplus officer is required to consume or possess alcoholic beverages on Enerplus premises. Consumption or possession of alcohol in Enerplus owned or leased vehicles or personal vehicles used for Enerplus business is strictly prohibited. For further information, please refer to the Alcohol and Drug Policy.

The possession, use, or distribution of firearms, weapons, and explosives is prohibited while on Enerplus premises, while conducting Enerplus business, or while in Enerplus vehicles on or off Enerplus premises, except as authorized under the Firearm Storage, Transportation and Use Standard found on the Safety & Social Responsibility section of the Enerplus website.

If evidence supports a reasonable suspicion of use, possession, or distribution of prohibited items, Enerplus reserves the right to conduct searches on Enerplus premises or in Enerplus owned or leased vehicles for such items.

Our Company

Document Retention

Employees must comply with Enerplus' department-specific document (physical and electronic) retention guidelines to ensure that all applicable laws and regulations are met. Each Employee should become familiar with and adhere to these guidelines. Additionally, when litigation or an investigation is pending, Employees are prohibited from modifying or destroying relevant documents or records, including Employees' personal files and electronic records. The consequences of modifying or destroying any relevant documents or records are severe and may include prosecution. An Employee who has any doubt about the legality or propriety of modifying or destroying any document or record should contact his/her supervisor or General Counsel before proceeding.

External Communications

From time to time, Employees may be contacted by government representatives or legal counsel representing other companies, government agencies, or individuals in connection with investigations that concern Enerplus, its business, counterparties, Employees, or suppliers. While Enerplus cooperates with all reasonable requests from government agencies and authorities related to Enerplus' business, an Employee receiving a request for information other than what is provided on a routine basis should decline to respond and immediately report the request to his/her supervisor and seek guidance from the Legal Department. Likewise, if an Employee receives a subpoena or other request to testify or produce documents in relation to Enerplus' business, a copy of the subpoena or request should be forwarded immediately to our General Counsel. All information provided should be truthful and accurate. Employees must never mislead any investigator and must never modify or destroy documents or records in response to an investigation.

Disclosure of Corporate Information; Trading Restrictions

Employees must not trade Enerplus securities while in possession of material, non-public corporate information. Employees must not use such material, non-public corporate information for their benefit or the benefit of others. Material corporate information is any information that, if known, might influence a reasonable investor's investment decision to buy, sell, or hold securities of Enerplus. Non-public means any corporate information that has not been released by Enerplus for public dissemination and which is intended to remain confidential until such authorized dissemination. With the exception of disclosure to Enerplus' advisors, Employees should not share material, non-public corporate information with anyone outside Enerplus (including family members) until it has been made public, regardless of how the information may or may not be used. These restrictions also apply to trading in securities of any other company (including, but not limited to, competitors, suppliers, and counterparties) if an Employee learns of any material, non-public information about that company during the course of his/her employment with Enerplus.

Employees must adhere to blackout restrictions posted on published blackout calendars. Trading blackouts are implemented to ensure that "insiders" do not have the advantage of information that has not been announced to the general investing public. "Insiders" are considered to be anyone who has access to information that has not been released to the public realm. Applicable securities laws dictate the protection of the entire investing public to ensure fairness. Should an individual breach insider trading rules they may be subject to significant penalties by regulatory authorities.

Announcements of material information will include scheduled and unscheduled announcements. Scheduled announcements include the release of quarterly financial statements, annual financial statements and annual reports of Enerplus, and in that regard, trading in Enerplus securities by Employees will be prohibited for a certain time before and after the release of financial statements. Unscheduled announcements may include the release of information relative to changes in the Corporation of a financial or structural nature, which may or may not require trading blackouts.

Management will make every attempt to inform Employees of changes to blackout periods. However, blackout periods may change without notice. Should you have any questions or require clarification regarding trading restrictions, it is your responsibility to direct these questions to General Counsel prior to trading any Enerplus securities.

Employees must report violations or misuse of material, non-public corporate information to our General Counsel immediately.

Directors and officers of Enerplus are required by securities regulations to make certain filings with securities commissions to report their holdings and transactions in Enerplus' securities. Questions about these laws should be directed to the General Counsel.

Directors and officers of Enerplus may not, directly or indirectly, buy, sell or enter into:

- any short sale of securities of Enerplus;
- any puts, call options or other rights or obligations to buy or sell securities of Enerplus;
- any derivative instruments, agreements or securities, the market price, value or payment obligations of which are derived from or based on the value of securities of Enerplus; or
- any other derivative instruments, agreements, arrangements or understanding (commonly known as equity monetization transactions) the effect of which is to alter, directly or indirectly, the director's or officer's economic interest in securities of Enerplus, or the director's or officer's economic exposure to Enerplus, with the exception of corporate equity hedges or normal course issuer bids.

Enerplus believes that the interests of the Corporation's directors and officers should be aligned with those of the Corporation's other shareholders. Engaging in the above activity frustrates our intention that directors and officers hold a meaningful ownership interest in Enerplus and bear the full risks and rewards of ownership.

Conflicts of Interest

Employees are not permitted to do anything that does not support the best interests of Enerplus. For example:

- An Employee should not use Enerplus property for his/her own material benefit.
- An Employee should not influence Enerplus' contractors or consultants for his/her own personal gain.
- An Employee, or his/her family members or friends, should not act on business opportunities or investments presented to Enerplus, other than for the benefit of the Corporation, that are not available to the public, without written permission from General Counsel.
- An Employee should not make or recommend decisions for Enerplus that might benefit the Employee, his/her family members, or friends financially.
- An Employee or their spouse should not own a five percent (5%) or more equity interest in any entity that sells supplies, furnishes services, or otherwise does business with Enerplus without written permission from General Counsel.
- An Employee or their spouse should not own a five percent (5%) or more equity interest in any entity that is a competitor of Enerplus without disclosing such interest.

Before acknowledging compliance with this Code, an Employee must report in writing any conflicts of interest to the People and Culture Department. If conflicts of interest arise after the Employee has acknowledged compliance, the Employee must report the conflicts immediately in writing to the People and Culture Department, which will disclose such conflicts to General Counsel.

During business hours, Employees should devote their full time and attention to Enerplus and their assigned job duties. Unrelated outside activities, business, or secondary employment are not permitted during business hours.

With the exception of Enerplus directors, no Employee of Enerplus should serve on the executive or board of any corporation that Enerplus does not control or have an ownership interest in without the written approval of Enerplus' General Counsel. It is acceptable to serve on the board of a non-profit, charitable, religious, or civic organization without prior written approval, provided it does not interfere with or impair the Employee's ability to perform their duties at Enerplus and represents a commitment of personal time.

To avoid potential conflicts of interest, it is against Enerplus' policy for Enerplus to extend loans to officers or directors. It is acceptable, however, for Enerplus to extend loans to Employees in certain instances (e.g. loans to purchase personal computers).

Confidential and Proprietary Information

Occasionally, Employees may know confidential information concerning Enerplus' business, including counterparties, suppliers, business contacts, Employees, or technical operations. Employees must keep this information confidential during and after their employment with Enerplus. Personal information relating to Enerplus counterparties, suppliers, business contacts or Employees must be treated in accordance with Enerplus' Privacy Policy.

Generally, any information stored by and/or processed by Enerplus is proprietary information. This confidential information includes computerized data, methods, techniques, and documentation relating to Enerplus' computing services, developed software, and third-party software.

Employees must be aware of their responsibilities regarding access to Enerplus' computer services, and the access, use, and disclosure of confidential information. Confidential and proprietary information must be used for Enerplus purposes only, never for personal gain. Enerplus prohibits Employees from releasing or misusing any confidential and proprietary Enerplus information.

Accounting and Reporting

Accurate documents are important during audits and other internal or external reviews. All Employees must comply with Enerplus' accounting and reporting procedures and make sure all books, records, accounts, and supporting papers are accurate and complete. Employees are forbidden to forge, falsify, or intentionally leave out important facts on any business documents of Enerplus which could mislead auditors or other internal or external reviewers.

Expense Accounts

Employee expense accounts are to be used only to reimburse Employees for items and activities that are purchased for Enerplus business. Employees must submit accurate expense reports of the money spent for this purpose.

Enerplus' Information Technology Resources

Corporate information, information systems and electronic communications are considered assets and valuable resources to Enerplus. Enerplus requires the appropriate use of these assets and their protection in a manner commensurate with their sensitivity, value and criticality. Any electronic communication of personal information must be in accordance with Enerplus' Privacy Policy.

All Employees are required to:

- Manage and protect corporate information, information systems and electronic communications in accordance with all Enerplus policies, standards and procedures, including statutory and regulatory requirements;

- Take accountability for appropriate security, access and retention of specific information they are responsible for; and

- Report incidents and assist in investigations relating to the misuse of information assets.

Enerplus' information technology resources, such as email and internet access, are provided to Employees in pursuit of Enerplus' business. While limited personal use of these resources is acceptable, Employees should not expect their use of these resources to be private or confidential. Personal use of these resources, such as accessing social networking/media websites (e.g. Facebook, Instagram, Twitter, YouTube, etc.), also should not interfere with Employee productivity or business processes.

Employees should take the same care in their electronic communications as they take when they communicate in person or by paper. Information and data are at risk when transmitted over the internet.

Employees shall not use Enerplus' information technology resources inappropriately, including the following prohibited activities:

- Accessing, viewing, downloading, storing or redistributing any material or message that is illegal or offensive;

- Activities designed to evade, compromise or otherwise exploit security controls;

- Possession or use of assessment and discovery tools that could be used to collect information to compromise the security of Enerplus' information system or launch attacks against other parties' information systems;

- The intentional creation and/or transmission of malicious code (viruses, worms, etc.);

- Malicious activity including, but not limited to: erasing, renaming or making unusable any software, data or information;

- Disclosing, gathering or using another Employee's account/password to access any information technology resources;

- Participation in chain letters or other forms of mass mailing or marketing; or

- Connecting non-Enerplus/personal devices (laptops, external hard/flash drives, etc.) directly to an Enerplus device or network unless authorized by the Information Services Department.

Enerplus does not allow Employees to copy or distribute copyrighted materials (e.g., software, database files, articles, graphics, music, movies, etc.) through Enerplus' email system or by any other means without confirming in advance from appropriate sources that Enerplus has the right to copy or distribute the material. Employees are not permitted to install any software on Enerplus' information systems without the express written consent of an executive with responsibility for the Information Services Department.

An Employee's logon IDs and passwords are intended for his/her use only and each Employee is responsible for all activity that occurs under their accounts. Employees must protect their accounts through the use of strong passwords.

Enerplus may access its information technology resources at any time as part of an internal audit or to investigate suspected unauthorized use, and may disclose the information it accesses to law enforcement or other third parties without prior consent of the sender or the recipient.

Employees should consult the Information Services Security Policies and the Information Services Security section of the Enerplus website for further policies, responsibilities, guidance and awareness related to information security.

<u>Internet/Intranet Site Development</u>

Enerplus' internet and intranet are important platforms to communicate Enerplus information to Employees, counterparties, and the public.

As such, the Corporation's Information Services Department and the People and Culture Department shall be solely responsible for and shall administer the creation and development of all Enerplus internet and intranet sites . From time to time and based on business need, access to internet or intranet pages may be granted to Employees for creation or revision of content. Employee and stakeholder suggestions for enhancement to the sites are encouraged.

<u>Corporate Logo</u>

The logos of Enerplus and its business units are considered property of Enerplus and must only be used for business purposes. Only the approved logos, which are available through the People and Culture Department and the intranet, may be used, and approval must be obtained prior to using any Enerplus logo on materials to be distributed outside of Enerplus. Re-creation or alteration of Enerplus' logos is not permitted.Acquisition of all logo items, such as apparel and office items, must be coordinated through the Stakeholder Engagement, Safety & Social Responsibility or Investor Relations teams.

Our Business Partners and Counterparties

<u>Relationships with Contractors and Suppliers</u>

Contractor and supplier relationships must be managed in a fair, equitable, and ethical manner consistent with this Code of Business Conduct, all applicable laws, and good business practices.

Enerplus promotes competitive procurement to the maximum extent practical and evaluates every supplier's products and services on the basis of technical excellence, quality, reliability, service, price, delivery, and other relevant objective factors. Enerplus prohibits Employees from making purchasing decisions on the basis of personal relationships, friendships, or the opportunity for personal financial gain.

Employees must respect the terms of supplier and contractor contracts and licensing agreements and safeguard all confidential information received from a contractor or supplier, including pricing, technology, or proprietary design information. This confidential information must not be disclosed to anyone outside Enerplus without the written permission of the supplier or contractor.

All contractors who exchange or receive personal information from Enerplus must have privacy policies and practices in compliance with applicable Canadian and United States federal, provincial and state laws.

<u>Anti-Corruption</u>

Enerplus is committed to honesty and integrity in all of its business operations and will actively avoid corruption. We recognize that we may operate in jurisdictions which have different standards of ethical behaviour. Regardless of location, Employees shall carry out their duties in accordance with the principles set out in this Code and, specifically, will comply with all applicable anti-bribery and fair practices legislation.

Acts of corruption, either direct or indirect, are prohibited. Accordingly, Employees shall not engage in any acts that are improper or could appear to be improper, including the following:

- Paying bribes or kickbacks to, or accepting bribes or kickbacks from, public officials or private individuals;
- Making facilitation payments;
- Failing to keep complete and accurate records of transactions;
- Approving payment of invoices or expenses without proper back-up or scrutiny;
- Engaging in joint ventures or retaining agents or consultants to deal with public officials without conducting adequate due diligence of the counterparty's previous activities or reputation.

Compliance with these principles will ensure that Enerplus' business activities are transparent and our commercial relationships are based upon honesty and fairness.

<u>Gifts and Entertainment</u>

Reasonable gifts and entertainment are a part of normal business courtesy and are not prohibited. In many cultures, exchanging gifts or entertainment is designed to foster trust in a business relationship. However, Employees should always use good judgment and discretion to avoid the appearance of impropriety or obligation. Enerplus Employees should be certain that any gifts given or received, or entertainment hosted or attended as a guest, do not violate the law, customary business practices, or this Code of Business Conduct.

While Employees may exchange or accept gifts with their counterparties and suppliers as part of normal business courtesy, no gift, favor, or payment should be accepted which imparts a future obligation on the Employee or was given in an attempt to influence decisions regarding the business of Enerplus. Additionally, the value of the gifts exchanged should be reasonable, and the exchanges should occur infrequently.

Likewise, while Employees may be participants in entertainment with their counterparties and suppliers as hosts or guests in the normal course of a business relationship, Employees must not be participants when the entertainment is an attempt to influence decisions regarding the business of Enerplus or imparts a future obligation on the Employee. Additionally, the value of the entertainment should be reasonable and the Employee's participation should occur infrequently. Finally, Employees are prohibited from participating in inappropriate entertainment as either a guest or a host.

Gifts and entertainment in excess of $300 may be accepted, if approved in advance by an executive officer. If a gift has been received but, given the circumstances, the gift is determined to be inappropriate, your manager may require the gift to be returned to the originator. An Employee who has any doubt about the propriety of a gift or entertainment should contact his/her supervisor or the People and Culture Department before accepting the gift or participating in the proposed activity.

<u>Obtaining and Using Competitor Information</u>

While information about our competitors, counterparties, and suppliers is a valuable asset, the law and our standards of appropriate business conduct require that our Employees obtain this information legally. It is not unusual to obtain information about other organizations, including our competitors, through legal and ethical means such as public documents, public presentations, journal and magazine articles, and other published and spoken information. However, Employees are prohibited from obtaining proprietary or confidential information about our competitors, counterparties, or suppliers through illegal means, or from using any proprietary or confidential information acquired during a prior employment relationship. It is also not acceptable to use or seek to acquire proprietary or confidential information when doing so would require anyone to violate a contractual arrangement, such as a confidentiality agreement with a prior employer. Employees are prohibited from taking any improper actions to gain information about our competitors, counterparties, and suppliers.

Our Communities

Environmental Compliance

Enerplus is dedicated to complying with all relevant environmental laws and regulations and requires Employees to comply with these laws and regulations as well. It is the duty of each Employee to report what he/she believes to be environmental violations to his/her supervisor or the Safety & Social Responsibility Department. For further information, please refer to the Safety & Social Responsibility Policy.

Political Contributions

Only Enerplus' President and CEO may authorize use of the Corporation's resources to support political activities. Employees must not use Enerplus' money, credit, property, or services for political activities. Outside of Enerplus business hours, Employees may participate in any political activities of their choice, but Enerplus will not support or reimburse Employees financially.

Requests for Information from the Media and Public

Enerplus' President and CEO, Senior Vice-Presidents, Vice-Presidents of Operations and the Investor Relations Department are authorized to work with the media directly, and may designate other Employees to serve as spokespersons for the Corporation in specific circumstances (e.g., emergency management). When Enerplus provides information to the news media, Enerplus has the obligation to report accurately and completely all related material facts. In order to ensure that Enerplus complies with its obligations, Employees who are contacted by the media for information regarding Enerplus' business activities and plans, financial information, or Enerplus' position on public issues, must refer the request to the Investor Relations Department. Likewise, all requests from the media for interviews must be directed to Investor Relations. Employees may not answer any questions from any member of the media unless they have participated in Enerplus' media training program and been designated as spokespersons.

Press Releases

Press releases allow Enerplus to announce important and relevant information to the public through the media. If a business unit or department within Enerplus anticipates the necessity for a press release to be created, the business unit or department must contact the Investor Relations Department to discuss the appropriateness of such a release and to provide the needed information. All press releases must be issued by the Investor Relations Department.

Public Speaking and Publishing Articles

Speeches and articles offer excellent opportunities for Enerplus and its Employees to present topics, ideas, and information of interest to business and professional audiences. These communications provide the public with a clearer understanding of Enerplus and its various business units. A speech or article on a professional topic written by an Employee for delivery to an audience or publication represents Enerplus. Speeches and articles must be approved by the Investor Relations Department prior to the speaking engagement or submission for publication. The Communications group may assist as well.

Social Networking and Blogs

Employees have the right to create personal blogs and postings on social networking websites. However, online misconduct can be grounds for discipline, even if it does not occur during business hours or using Enerplus' resources. Inappropriate content for online employee postings includes, but is not limited to, the following:

- Enerplus' confidential or proprietary information;
- Information concerning Enerplus or Employees that would violate this Code or any other Enerplus policies, including the Privacy Policy; and
- Negative comments about Enerplus or Employees, or that would harm the reputation of Enerplus or its Employees.

Employees should consult the Social Media Guidelines posted on the intranet for further information.

Community Involvement

Enerplus directly and through its Employees contributes to the general well-being and improvement of towns, cities, and regions where it has operations. Enerplus provides support to worthwhile community programs in areas such as social welfare, health, education, and arts and culture to promote the development of positive relationships in the areas where we have business interests. Enerplus also encourages the recruitment of qualified local personnel where practical. All Enerplus community involvement activities and requests for corporate contributions must be approved by the Communications group in coordination with the Stakeholder Engagement team.

While Enerplus encourages Employees to participate in charitable organizations and other community activities of their choice, these outside activities should not interfere with job duties. Accordingly, prior approval from your manager must be obtained when participation is supported by Enerplus and when utilizing Enerplus resources (including work time, e.g. days of caring). Where participation is on personal time and does not conflict with job duties then approval is not required. No Employee may pressure another Employee to express a view that is contrary to a personal belief or to contribute to or support political, religious, or charitable causes.

Community Projects

When a new project or business issue affects a local community, the business unit should seek the guidance of the Stakeholder Engagement team and the Communications group to help facilitate communications with the affected community. These groups will serve as support, proactively building and maintaining relationships with local communities as project development occurs. This will include developing a consistent platform to help educate landowners and communities on Enerplus' operations and safety programs.

REPORTING VIOLATIONS AND RESOURCES FOR GUIDANCE

This Code and other Enerplus policies provide general information for seeking guidance or reporting violations of the Code to supervisors, department heads, the People and Culture Department or our General Counsel. For more serious breaches of this Code, or if you have not received a satisfactory response, please refer to the Whistleblower Policy discussed below.

Whistleblower Policy

Enerplus has instituted a Whistleblower Policy to provide for the reporting and review of concerns relating to accounting and auditing matters, as well as other corporate misconduct and breaches of this Code of Business Conduct. Like the Code of Business Conduct, the Whistleblower Policy is designed to encourage ethical behaviour by all Enerplus Employees. Further details, and procedures for submitting a report, are set out in the Whistleblower Policy.

Disciplinary Action

This Code is intended to help Employees conduct themselves in a manner consistent with our values. Employees may face disciplinary action if they:

- Violate this Code
- Encourage or help other Employees to violate this Code
- Condone other Employees who violate this Code
- Fail to report a Code violation
- Conceal a Code violation
- Retaliate against any Employee who reports a Code violation in good faith

- Fail as an officer, director, manager, or supervisor to take appropriate steps to ensure compliance with this Code

Disciplinary action may include one or more of the following:

- A warning
- A written reprimand
- Mandatory reimbursement of losses or damages
- Suspension
- Demotion
- Termination of employment with Enerplus
- Referral for criminal prosecution or civil action

Management has the discretion to determine the level and type of discipline that is appropriate in any given circumstance. For more information please refer to the Progressive Discipline Procedure.

Monitoring

Enerplus will monitor compliance with its policies and procedures, including this Code.

Questions/Effect of this Code of Business Conduct

This Code is not a comprehensive listing of every Enerplus policy or applicable law. If questions arise about what this Code means or how it should be applied, Employees should contact their supervisor, department head or the People and Culture Department.

Sources of Information

Manager, People & Culture	(403) 298-2277
Manager, Safety & Social Responsibility	(403) 693-5054
VP, General Counsel & Corporate Secretary	(403) 298-4413

EXHIBIT 99.12

Supplemental Information About Oil and Gas Producing Activities (unaudited)

The following disclosures, including proved reserves, future net cash flows, and costs incurred attributable to Enerplus' crude oil and natural gas operations have been prepared in accordance with the provisions of the Financial Accounting Standards Board's Accounting Standards Update (ASU) No. 2010-03 "Extractive Activities – Oil and Gas (Topic 932) (the "ASU"). The standard requires the use of a 12 month average price to estimate proved reserves calculated as the unweighted arithmetic average of first-day-of-the-month prices within the 12 month period prior to the end of the reporting period. Proved reserves and production volumes are presented net of royalties in accordance with U.S. protocol.

A. PROVED OIL AND NATURAL GAS RESERVE QUANTITIES

Users of this information should be aware that the process of estimating quantities of "proved developed" and "proved undeveloped" crude oil, natural gas and natural gas liquids is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Future fluctuations in prices and costs, production rates, or changes in political or regulatory environments could cause the Corporation's reserves to be materially different from that presented.

Proved reserves, proved developed reserves and proved undeveloped reserves are defined under the ASU. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulation. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The proved reserves disclosed herein are determined according to the definition of "proved reserves" under NI 51-101 which may differ from the definition provided in SEC rules, however the difference should not be material. The reserves data presented in this Exhibit are a summary of 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. See "*Presentation of Enerplus' Oil and Gas Reserves, Contingent Resources, and Production Information*" in Enerplus' Annual Information Form. All cost information in this section is stated in Canadian dollars and is calculated in accordance with accounting principles generally accepted in the United States of America ("**U.S. GAAP**").

Subsequent to December 31, 2016, no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of proved reserves as of that date.

Enerplus' December 31, 2016 proved crude oil, natural gas and natural gas liquids reserves are located in western Canada, primarily in Alberta, British Columbia and Saskatchewan, as well as in the United States, primarily in the states of Montana, North Dakota and Pennsylvania. Enerplus' net proved reserves summarized in the following chart represent the Corporation's lessor royalty, overriding royalty, and working interest share of reserves, after deduction of any Crown, freehold and overriding royalties:

	Canada		United States		Total		Total
	Oil and NGLs (Mbbls)	Natural Gas (MMcf)	Oil and NGLs (Mbbls)	Natural Gas (MMcf)	Oil and NGLs (Mbbls)	Natural Gas (MMcf)	All Products (Mboe)
Proved Developed and Undeveloped Reserves at December 31, 2013	**55,470**	**231,274**	**47,580**	**374,779**	**103,050**	**606,053**	**204,059**
Purchases of reserves in place	—	—	54	28	54	28	59
Sales of reserves in place	(896)	(32,162)	(89)	(8,387)	(985)	(40,549)	(7,743)
Discoveries and extensions	2,715	27,175	16,498	139,289	19,213	166,464	46,957
Revisions of previous estimates	643	54,050	(263)	48,731	379	102,781	17,509
Improved recovery	13	462	—	—	13	462	90
Production	(5,618)	(49,865)	(7,255)	(60,010)	(12,873)	(109,875)	(31,185)
Proved Developed and Undeveloped Reserves at December 31, 2014	**52,327**	**230,934**	**56,524**	**494,430**	**108,851**	**725,364**	**229,745**
Purchases of reserves in place	—	—	—	—	—	—	—
Sales of reserves in place	(11,869)	(33,192)	(248)	(111)	(12,117)	(33,303)	(17,667)
Discoveries and extensions	1,276	2,769	4,397	4,351	5,673	7,120	6,860
Revisions of previous estimates	(1,451)	(52,613)	1,673	(134,840)	222	(187,453)	(31,021)
Improved recovery	—	—	—	—	—	—	—
Production	(5,211)	(44,666)	(8,644)	(65,438)	(13,855)	(110,104)	(32,206)
Proved Developed and Undeveloped Reserves at December 31, 2015	**35,072**	**103,232**	**53,702**	**298,392**	**88,774**	**401,624**	**155,711**
Purchases of reserves in place	1,434	12,228	—	—	1,434	12,228	3,472
Sales of reserves in place	(2,954)	(49,069)	(4,204)	(2,998)	(7,158)	(52,067)	(15,836)
Discoveries and extensions	83	—	12,515	28,288	12,598	28,288	17,313
Revisions of previous estimates	(234)	9,556	(7,722)	100,812	(7,956)	110,368	10,439
Improved recovery	—	—	—	—	—	—	—
Production	(4,391)	(26,526)	(8,465)	(64,588)	(12,856)	(91,114)	(28,042)
Proved Developed and Undeveloped Reserves at December 31, 2016	**29,009**	**49,421**	**45,826**	**359,906**	**74,836**	**409,327**	**143,056**
Proved Developed Reserves							
December 31, 2013	47,316	225,005	33,147	265,464	80,463	490,469	162,208
December 31, 2014	44,149	211,809	42,594	402,647	86,743	614,456	189,152
December 31, 2015	30,517	101,665	38,572	288,684	69,089	390,349	134,147
December 31, 2016	**25,743**	**48,243**	**33,799**	**350,294**	**59,542**	**398,537**	**125,965**
Proved Undeveloped Reserves							
December 31, 2013	8,154	6,269	14,433	109,315	22,587	115,584	41,851
December 31, 2014	8,178	19,125	13,930	91,783	22,108	110,908	40,593
December 31, 2015	4,555	1,567	15,130	9,708	19,685	11,275	21,564
December 31, 2016	**3,267**	**1,178**	**12,027**	**9,612**	**15,294**	**10,790**	**17,092**

Purchases of reserves in place

In 2016, the Company acquired working interests in the Ante Creek North oil property located in Alberta. This purchase represented all of the purchase of reserves in place for Enerplus in 2016.

Sales of reserves in place

In 2014, the Company sold working interests in developed and undeveloped land in eighteen predominantly natural gas properties in Alberta and one property in British Columbia.

Additionally, the Company sold all interests in the Jonah natural gas property in Wyoming which accounts for all of the United States sales of reserves in place volumes for 2014.

In 2015, the Company sold working interests in developed and undeveloped land in two oil properties located in Alberta and Saskatchewan and 11 predominantly shallow natural gas properties also located in Alberta and Saskatchewan.

In 2016, the Company sold working interests in developed and undeveloped land in six oil properties located in Alberta and 12 natural gas properties located in Alberta and Saskatchewan.

Additionally, the Company sold almost all non-operated working interests in the Bakken/Three Forks crude oil property in North Dakota, which accounts for all of the United States sales of reserves in place for 2016.

Discoveries and extensions

United States discoveries and extensions for the periods ending December 31, 2014, 2015 and 2016 were primarily due to successful well development of the Company's Bakken/Three Forks crude oil property in North Dakota, and the Marcellus natural gas property in Pennsylvania. In these periods, the Company added 16,498 MBbl, 4,397 Mbbl and 12,515 MBbl of net proved oil and NGLs reserves with respect to Bakken/Three Forks properties in 2014, 2015 and 2016, respectively. The Company added 130,400 MMcf, 1,810 MMcf and 22,017 MMcf of net proved natural gas reserves in 2014, 2015 and 2016, respectively, in the Marcellus natural gas property.

Canadian natural gas discoveries and extensions for the period ending December 31, 2014, accounted for an increase of 27,175 MMcf net proved reserves primarily due to the Company's Alberta drilling program. Roughly half of these reserves were producing as of December 31, 2014. The largest undeveloped portion of the addition was an addition of 10,549 MMcf in the Wilrich.

In 2015, Canadian discoveries and extensions accounted for an increase of 1,276 MBbl of net proved oil and NGLs reserves and 2,769 MMcf of net proved natural gas reserves, primarily due to the expansion of the Med Hat Glauconitic C polymer floods.

In 2016, Canadian discoveries and extensions accounted for an increase of 83 MBbl of net proved oil and NGLs reserves due to assigning reserves to a location in the Saskatchewan Ratcliffe oil property.

Revisions of previous estimates

Revisions to United States oil reserves in 2014 were due to the improved production performance of the Bakken/Three Forks oil property. The revisions to United States natural gas reserves in 2014 were due to improved production performance of the Marcellus natural gas property.

In 2015, negative revisions to United States natural gas reserves were primarily due to a decrease in the constant price gas price forecast versus 2014, causing undeveloped reserves to become uneconomic and therefore removed.

In 2016, negative revisions to United States oil reserves were primarily due to the removal of undeveloped locations that would not be drilled within five years of initial booking. Positive revisions to United States natural gas reserves were primarily due to improved production performance of the Marcellus natural gas property.

In 2014, the positive revisions to Canadian natural gas reserves were primarily due to an increase in the constant gas price forecast versus 2013**.**

In 2015, the negative revisions to Canadian natural gas reserves were primarily due to a decrease in the constant gas price forecast versus 2014.

In 2016, the positive revisions to Canadian natural gas reserves were due to a slightly higher gas price forecast and slightly lower operating costs.

B. CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation and depletion, including impairments, relating to Enerplus' oil and gas exploration, development and producing activities are as follows:

	2016	2015	2014
		(in $ thousands)	
Capitalized costs[1]	**$ 13,567,390**	$ 13,541,670	$ 12,478,953
Less accumulated depletion, depreciation and impairment	**(12,840,938)**	(12,375,083)	(9,846,479)
Net capitalized costs	**$ 726,452**	$ 1,166,587	$ 2,632,474

Note:

(1) Includes capitalized costs of proved and unproved properties.

C. COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred in connection with oil and gas producing activities are presented in the table below. Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties, including an allocation of purchase price on business combinations that result in property acquisitions. Development costs include asset retirement costs capitalized and the costs of drilling and equipping development wells and facilities to extract, gather and store oil and gas, along with an allocation of overhead. Exploration costs include costs related to the discovery and the drilling and completion of exploratory wells in new crude oil and natural gas reservoirs.

	For the Year Ended December 31, 2016		
	Canada	United States	Total
		(in $ thousands)	
Acquisition of properties:			
Proved	$ 49,043	$ 1,847	$ 50,890
Unproved	65,401	9,835	75,236
Exploration costs	740	2,158	2,898
Development costs	52,704	162,427	215,131
	$ 167,888	$ 176,267	$ 344,155

	For the Year Ended December 31, 2015		
	Canada	United States	Total
		(in $ thousands)	
Acquisition of properties:			
Proved	$ 3,610	$ 2,658	$ 6,268
Unproved	3	3,282	3,285
Exploration costs	12,777	12,014	24,791
Development costs	104,337	328,117	432,454
	$ 120,727	$ 346,071	$ 466,798

	For the Year Ended December 31, 2014		
	Canada	United States	Total
		(in $ thousands)	
Acquisition of properties:			
Proved	$ 38	$ 6,814	$ 6,852
Unproved	1,952	9,687	11,639
Exploration costs	44,612	1,668	46,280
Development costs	274,371	496,531	770,902
	$ 320,973	$ 514,700	$ 835,673

D. RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

The following table sets forth revenue and direct cost information relating to Enerplus' oil and gas producing activities for the years ended December 31, 2016, 2015 and 2014:

	For the Year Ended December 31, 2016		
	Canada	United States	Total
		(in $ thousands)	
Revenue			
Sales[1]	$ 233,391	$ 489,341	$ 722,732
Deduct[2]			
Production costs[3]	151,151	241,330	392,481
Depletion, depreciation and accretion ("DD&A")	126,061	202,903	328,964
Impairment	89,359	211,812	301,171
Current and deferred income tax provision (recovery)	(24,376)	(212,822)	(237,198)
Results of operations for oil and gas producing activities	$ (108,804)	$ 46,118	$ (62,686)
DD&A per net BOE unit of production	$ 14.31	$ 10.55	$ 11.73

	For the Year Ended December 31, 2015		
	Canada	United States	Total
		(in $ thousands)	
Revenue			
Sales[1]	$ 369,559	$ 514,833	$ 884,392
Deduct[2]			
Production costs[3]	245,162	260,911	506,073
Depletion, depreciation and accretion ("DD&A")	198,641	309,538	508,179
Impairment	286,700	1,065,728	1,352,428
Current and deferred income tax provision (recovery)	(53,400)	(114,075)	(167,475)
Results of operations for oil and gas producing activities	$ (307,544)	$(1,007,269)	$ (1,314,813)
DD&A per net BOE unit of production	$ 15.70	$ 15.83	$ 15.78

	For the Year Ended December 31, 2014		
	Canada	United States	Total
		(in $ thousands)	
Revenue			
Sales[1]	$ 689,135	$ 837,059	$ 1,526,194
Deduct[2]			
Production costs[3]	287,989	243,312	531,301
Depletion, depreciation and accretion ("DD&A")	236,028	331,614	567,642
Current and deferred income tax provision (recovery)	64,203	73,626	137,829
Results of operations for oil and gas producing activities	$ 100,915	$ 188,507	$ 289,422
DD&A per net BOE unit of production	$ 16.95	$ 19.22	$ 18.20

Notes:

(1) Sales are presented net of royalties

(2) The costs deducted in this schedule exclude corporate overhead, interest expense and other costs which are not directly related to oil and gas producing activities.

(3) Production costs include transportation costs and production taxes.

E. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND NATURAL GAS RESERVE QUANTITIES

The following tables set forth the standardized measure of discounted future net cash flows from projected production of the Enerplus' crude oil and natural gas reserves:

	As at December 31, 2016		
	Canada	United States	Total
		(in $ millions)	
Future cash inflows	$ 1,171	$ 2,073	$ 3,243
Future production costs	660	1,025	1,685
Future development and asset retirement costs	237	308	546
Future income tax expenses	—	—	—
Future net cash flows	$ 273	$ 739	$ 1,012
Deduction: 10% annual discount factor	81	241	322
Standardized measure of discounted future net cash flows	$ 192	$ 498	$ 690

	As at December 31, 2015		
	Canada	United States	Total
		(in $ millions)	
Future cash inflows	$ 1,871	$ 2,686	$ 4,556
Future production costs	1,078	1,203	2,281
Future development and asset retirement costs	216	564	780
Future income tax expenses	—	—	—
Future net cash flows	$ 577	$ 919	$ 1,496
Deduction: 10% annual discount factor	190	362	552
Standardized measure of discounted future net cash flows	$ 388	$ 556	$ 944

	As at December 31, 2014		
	Canada	United States	Total
		(in $ millions)	
Future cash inflows	$ 5,447	$ 6,344	$11,791
Future production costs	2,401	2,024	4,426
Future development and asset retirement costs	430	615	1,045
Future income tax expenses	316	903	1,219
Future net cash flows	$ 2,301	$ 2,802	$ 5,102
Deduction: 10% annual discount factor	931	1,194	2,125
Standardized measure of discounted future net cash flows	$ 1,370	$ 1,608	$ 2,977

F. CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND NATURAL GAS RESERVES

	2016	2015	2014
		(in $ millions)	
Beginning of year	**$ 944**	$ 2,977	$ 2,519
Sales of oil and natural gas produced, net of production costs	**(329)**	(378)	(996)
Net changes in sales prices and production costs	**(432)**	(3,613)	232
Changes in previously estimated development costs incurred during the period	**205**	461	810
Changes in estimated future development costs	**1**	(251)	(711)
Extension, discoveries and improved recovery, net of related costs	**78**	116	801
Purchase of reserves in place	**42**	—	—
Sales of reserves in place	**(106)**	(222)	(44)
Net change resulting from revisions in previous quantity estimates	**188**	723	163
Accretion of discount	**79**	285	247
Net change in income taxes	—	537	(151)
Other significant factors (Exchange rate)	**22**	309	107
End of year	**$ 690**	$ 944	$ 2,977