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, 2021 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)

Enerplus Resources (USA) Inc
US Bank Tower, Suite 2200, 950 - 17th Street
Denver, Colorado, United States of America 80202-2805
(720) 279-5500

(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	Trading Symbol	Name of each exchange on which registered
Common Shares	ERF	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.

243,852,379 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 every Interactive Data File required to be submitted 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 such files).

Yes ☒ No ☐

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act.

☐

Auditor Name: KPMG LLP Auditor Location: Calgary, Canada Auditor Firm ID: 85

† The term “new or revised financial accounting standard” refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark whether the registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

This annual report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the registrant’s Registration Statements under the Securities Act of 1933 on Form F-10 (File No. 333-257151) and Form S-8 (File Nos. 333-200583 and 333-171836).

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 "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plan", "intend", "guidance", "objective", "strategy", "should", "believe" 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, 2021, 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, 2021, 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

The registrant elected to change its reporting currency from Canadian dollars to U.S. dollars starting for the year ended December 31, 2021. All prior periods have been restated in U.S. dollars.

A. Annual Information Form

The Registrant's Annual Information Form for the year ended December 31, 2021 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, 2021, 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, 2021 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, 2021, 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, 2021, 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. Jeffrey W. Sheets, a member and the chair 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 31, 2022. There were no amendments made to the Code of Business Conduct of a substantive nature. During the fiscal year ended December 31, 2021, 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.

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

The required disclosure is included under the heading “Appendix E – Audit & Risk Management Committee Disclosure Pursuant to National Instrument 52-110 – External Auditor Service Fees” in the Registrant’s Annual Information Form for the fiscal year ended December 31, 2021 attached as Exhibit 99.1 to this Annual Report on Form 40-F. All audit and non-audit fees paid to KPMG LLP 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.

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 KPMG LLP 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 KPMG LLP described above is compatible with maintaining that firm’s independence from the Registrant.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant does not have any commitments or obligations, including contingent obligations, arising from arrangements with unconsolidated entities or persons (which are not otherwise discussed in the Registrant's Management’s Discussion and Analysis for the year ended December 31, 2021 attached as Exhibit 99.3 to this Annual Report on Form 40-F) that have or are reasonably likely to have a material current or future effect on a registrant’s financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, cash requirements, or capital resources.

CONTRACTUAL OBLIGATIONS

Disclosure regarding the Registrant’s contractual obligations is provided under the heading “Liquidity and Capital Resources – Commitments and Contingencies” in the Registrant’s Management’s Discussion and Analysis for the year ended December 31, 2021 attached as Exhibit 99.3 to this Annual Report on Form 40-F, which disclosure is incorporated by reference herein, and in Note 18 to the Registrant’s audited annual consolidated financial statements for the year ended December 31, 2021 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 Jeffrey W. Sheets (Committee Chair), Judith D. Buie, and Sheldon B. Steeves. Hilary A. Foulkes, the Chair 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, 2022

EXHIBIT INDEX

99.1	Annual Information Form for the year ended December 31, 2021 dated February 24, 2022.
99.2	Audited annual consolidated financial statements for the year ended December 31, 2021.
99.3	Management’s Discussion and Analysis for the year ended December 31, 2021.
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.
101	Interactive Data File.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

ANNUAL INFORMATION FORM

For the year ended December 31, 2021

February 24, 2022

TABLE OF CONTENTS | Page

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, 2022 for the year ended December 31, 2021 and all appendices hereto.**

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

"**AECO**" means the Canadian benchmark trading price for natural gas

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

"**Bruin Acquisition**" means the acquisition by Enerplus USA of all of the equity interests of Bruin E&P HoldCo, LLC, a Delaware limited liability company, completed on March 10, 2021. See "*General Development of the Business – Developments in the Past Three Years*"

"**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

"**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 SLL Credit Facility, the Term 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

"Dunn County Acquisition" means the acquisition by Enerplus USA of certain assets in the Willison Basin from Hess Bakken Investments II, LLC, completed on April 30, 2021. See "*General Development of the Business – Developments in the Past Three Years*"

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

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

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

"**ESG**" means environmental, social and governance

"**ESG Policy**" means the Corporation's Environmental, Social and Governance Policy

"**Financial Statements**" means the audited consolidated financial statements of the Corporation as at December 31, 2021 and 2020 and for the three years ended December 2021, 2020 and 2019

"**GHG**" means greenhouse gas

"**GLJ**" means GLJ Ltd., independent petroleum consultants

"**H&S Policy**" means the Corporation's Health & Safety Policy

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

"**McDaniel Reports**" means, collectively, the independent engineering evaluations of certain of the Corporation's crude oil, natural gas liquids and natural gas reserves in Canada and certain of the Corporation's oil, natural gas liquids and natural gas reserves in the United States, and the Corporation's contingent resources associated with its North Dakota properties, prepared by McDaniel effective December 31, 2021 utilizing the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2022

"**MD&A**" means management's discussion and analysis for the year ended December 31, 2021

"**NAFTA**" means North American Free Trade Agreement

"**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, 2021, utilizing the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2022

"**NYMEX**" means the New York Mercantile Exchange, a U.S.-based commodities futures market

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

"**Scope 1 Emissions**" means all direct GHG emissions

"**Scope 2 Emissions**" means indirect GHG emissions from consumption of purchased electricity, heat, or steam

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

"**Senior Unsecured Notes**" means, as at December 31, 2021, the US$303.8 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*"

"**SLL Credit Facility**" means, as at December 31, 2021, the Corporation's US$900 million senior, unsecured, covenant-based sustainability-linked revolving credit facility with a syndicate of financial institutions. See "*Description of Capital Structure – SLL Credit Facility and Term Facility*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*"

"**Sproule**" means Sproule Associates Limited, independent petroleum consultants

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

"**TCFD**" means the Task Force on Climate-related Financial Disclosures

"**Term Facility**" means a US$400 million senior, unsecured, covenant-based term credit facility with a syndicate of financial institutions maturing on March 10, 2024 which, subsequent to December 31, 2021, was converted into a revolving bank credit facility with no other amendments. See "*Description of Capital Structure – SLL Credit Facility and Term Facility*"

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

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

"**USMCA**" means United States-Mexico-Canada Agreement

"**WTI**" means West Texas Intermediate crude oil that serves as the benchmark crude oil for NYMEX crude oil contracts delivered at Cushing, Oklahoma

Abbreviations and Conversions

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

API	American Petroleum Institute gravity, a measure of how heavy or light a petroleum liquid is compared to water
bbls	barrels, with each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/day	barrels per day
Bcf	one billion cubic feet
BOE(1)	barrels of oil equivalent
BOE/day(1)	barrels of oil equivalent per day
Mbbls	one thousand barrels
MBOE(1)	one thousand barrels of oil equivalent
Mcf	one thousand cubic feet
Mcf/day	one thousand cubic feet per day
Mcfe	one thousand cubic feet equivalent
Mcfe/d	one thousand cubic feet equivalent per day
MMBOE(1)	one million barrels of oil equivalent
MMbtu	one million British Thermal Units
MMcf	one million cubic feet
Mt	one million tonnes
NGLs	natural gas liquids
NPV	net present value of future net revenue, discounted at 10%

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. For further information, see "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information – Barrels of Oil Equivalent*".

In this Annual Information Form, unless otherwise indicated, all dollar amounts are in U.S. dollars and all references to "**$**" and "**US$**" are to U.S. dollars. References to "**CDN$**" are to Canadian dollars. On December 31, 2021, the exchange rate for one Canadian dollar, expressed in U.S. dollars and based upon the closing rate from Bloomberg, was US$0.7913**.** The average exchange rate in 2021 for one Canadian dollar, expressed in U.S. dollars and based upon the average closing rate from Bloomberg, was US$0.7977.

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

DISCLOSURE OF RESERVES AND PRODUCTION INFORMATION

Except for the information presented in Appendix B and as otherwise noted below, all oil and gas information presented in this Annual Information Form has been prepared and is presented in accordance with the Canadian disclosure standards set forth in NI 51-101 ("**Canadian Standards**").

The oil and gas reserves information of the Corporation contained in Appendix B, effective as at December 31, 2021, is prepared and presented in accordance with the provisions of the Financial Accounting Standards Board's ASC Topic 932 Extractive Activities – Oil and Gas ("**ASC 932**"), which generally utilize definitions and estimations of proved reserves that are consistent with Rule 4-10 of Regulation S-X promulgated by the SEC (the "**U.S. Rules**"), but does not necessarily include all of the disclosure required by the SEC disclosure standards set forth in Subpart 1200 of Regulation S-K (collectively, the "**U.S. Standards**"). Concurrent to the evaluation of the Corporation's Canadian NI 51-101 Standards reserves, McDaniel and NSAI prepared and reviewed estimates of the Corporation's reserves under the U.S. Standards. The practice of preparing production and reserves data under NI 51-101 differs from the U.S. Standards. The significant differences between the two reporting requirements are described under *"— Notice to U.S. Readers*", below.

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. Readers should also refer to the Report on Reserves Data and Contingent Resources Data by McDaniel and NSAI attached as Appendix C and the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix D. 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, 2021 and the preparation dates for such information are January 31, 2022 for the McDaniel Reports and February 8, 2022 for the NSAI Report.

For information regarding contingent resources of the Corporation and its presentation in accordance with NI 51-101, see Appendix A.

In this Annual Information Form, all oil and natural gas production volumes are presented on a "net" basis, as described under " - *Interests in Reserves, Contingent Resources, Production, Wells and Properties*" below, unless expressly indicated that it is being presented on a "gross" basis. Previously, the Corporation presented production volumes on a "company interest" basis, which was calculated as its working interest (operating and non-operating) share before deduction of royalties plus the Corporation's royalty interests. With these changes, production volumes presented by the Corporation on a "net" basis are expected to be lower than those presented historically. The Corporation believes, however, this change in presentation to "net" production in conjunction with the change in reporting currency to U.S. dollars (see "*Presentation of Financial Information*"), will facilitate a more direct comparison to other U.S. exploration and production companies.

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

NOTICE TO U.S. READERS

Except for the information set forth in Appendix B, all data on oil and natural gas reserves contained in this Annual Information Form has generally been prepared and is presented in accordance with Canadian disclosure standards and specifically in accordance with NI 51-101, which are not comparable in all respects to U.S. Standards or other foreign disclosure standards. The primary differences between the two reporting frameworks include:

- Under NI 51-101 and Canadian industry practice, reserves and production are reported using gross volumes, while the U.S. Standards and U.S. industry practice is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments, plus royalty interests. As discussed above, certain oil and gas production volumes in this Annual Information Form are presented on a net basis.

- Under NI 51-101, the Corporation has determined and disclosed estimated future net revenue from its reserves using forecast prices and escalating costs, whereas the U.S. Standards require that reserves estimates be prepared using an unweighted average of the closing prices for the applicable commodity on the first day of each of the twelve months preceding the Corporation's fiscal year-end, with the option of also disclosing reserves estimates based upon future or other prices and constant costs.

- NI 51-101 requires that reserves and other data be reported on a more granular product type bases than required under the U.S. Standards.

- NI 51-101 requires that proved undeveloped reserves be reviewed annually for retention or reclassification if development has not proceeded as previously planned, while the U.S. Standards specify a five-year limit after initial booking for the development of proved undeveloped reserves.

- 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.

As a consequence of the foregoing, except for the reserves information set forth in Appendix B, which has been prepared in accordance with U.S. Standards, the Corporation's reserves estimates and certain production volumes that are presented on a gross basis may not be comparable to those made by companies utilizing U.S. Standards. 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.

For certain oil and gas information prepared and presented in accordance with ASC 932 and U.S. Rules, see Appendix B.

BARRELS OF OIL 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. The conventions BOEs, MBOEs and MMBOEs may be misleading, particularly if used in isolation because 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

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.

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

"**gross**" means:

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

ii. in relation to wells, the total number of wells in which the Corporation has an interest

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

"**net**" means:

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

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

iii. in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation "**working interest**" means the percentage of undivided interest held by the Corporation in the oil and/or natural gas or mineral lease granted by the mineral owner (Crown or freehold), which interest gives the Corporation the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

RESERVES CATEGORIES AND LEVELS OF CERTAINTY FOR REPORTED RESERVES

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

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

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

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

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

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

DEVELOPMENT AND PRODUCTION STATUS

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

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

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

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

DESCRIPTION OF PRICE AND COST ASSUMPTIONS

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

i. generally accepted as being a reasonable outlook of the future

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

Presentation of Financial Information

The Corporation presents its financial information in accordance with U.S. GAAP. Beginning with its December 31, 2021 fiscal year-end reporting, the Corporation has elected to change its reporting currency from Canadian dollars to U.S. dollars since the majority of its crude oil and natural gas properties are in the U.S., and to facilitate a more direct comparison to other U.S. exploration and production companies. The change in reporting currency is a voluntary change, which is accounted for retrospectively. All relevant prior periods have been restated in U.S. dollars using the procedures outlined in the Corporation's Financial Statements (see Note 2), unless otherwise stated.

This Annual Information Form references certain financial measures, including "capital spending", which are "supplementary financial measures" under National Instrument 52-112. See "Other Financial Measures" in the MD&A for additional detail regarding such measures, which section is incorporated by reference in this Annual Information Form.

The Corporation continues to qualify as a foreign private issuer for the purposes of its U.S. securities filings based on the most recent assessment performed as at June 30, 2021. The Corporation is required to reassess this conclusion annually, at the end of the second quarter. See "*Risk Factors – The Corporation could lose its status as a "foreign private issuer" in the United States, which may result in additional compliance costs and restricted access to capital markets*".

Forward-Looking Statements and Information

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

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

- the quantity of, and future net revenues from, the Corporation's reserves and/or contingent resources
- crude oil, NGLs and natural gas production levels
- commodity prices, foreign currency exchange rates and interest rates
- operating expenditures
- current capital spending programs, drilling programs, development plans and other future expenditures, including the planned allocation of capital spending among the Corporation's properties and the sources of funding for such expenditures
- supply and demand for oil, NGLs and natural gas
- the Corporation's business strategy, including its asset and operational focus
- future acquisitions and divestments, and future growth potential
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves and/or resources through acquisitions and development
- schedules for and timing of certain projects and the Corporation's strategy for growth
- the Corporation's future operating and financial results

- the Corporation's tax pools and the time at which the Corporation may incur certain income or other taxes
- treatment of, and compliance by the Corporation with, governmental and other regulatory regimes and tax, environmental and other laws
- the Corporation’s ESG strategy, including specific targets relating to GHG emissions and freshwater use reductions, as well as climate change-related initiatives
- estimates of the Corporation’s future abandonment and reclamation obligations
- future dividends that may be paid by the Corporation
- future repurchases of Common Shares by the Corporation

The forward-looking information contained in this Annual Information Form reflects several material factors and expectations and assumptions made by the Corporation including, without limitation: stability, or no further deterioration, in the global economic and market environment, including from the COVID pandemic, variations thereof, and/or future pandemics, epidemics, or other world-wide health crises; 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, repurchase shares, pay dividends and other requirements or strategic initiatives, 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 crude oil and natural gas properties in the manner currently contemplated; a lack of infrastructure, government regulations or export bans do not result in the Corporation or a third party curtailing its production and/or receiving reductions to its realized prices; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; the estimates of the Corporation's reserves and resources volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; and there will be sufficient availability of services and labour to conduct the Corporation's operations as planned.

The Corporation's current 2022 capital spending budget of between US$370 to $US430 million contained in this Annual Information Form assumes: a WTI price of US$75.00 per barrel, a Bakken crude oil price differential of US$0.50 per barrel below WTI, a NYMEX natural gas price of US$4.00 per Mcf, a Marcellus natural gas price differential of US$0.75 per Mcf below NYMEX and a foreign exchange rate of CDN/USD 0.79.

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

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

- ongoing volatility in market prices for crude oil, NGLs and natural gas, including changes in supply or demand for those products, and the Corporation's realized prices
- actions by governmental or regulatory authorities, including as a result of ongoing global pandemic or mandated production curtailments, potential export bans initiated by governments or different interpretations of applicable laws, treaties or administrative positions, as well as changes in income tax laws or changes in royalty regimes and incentive programs relating to the oil and gas industry
- changes in general economic, market (including credit market) and business conditions in North America and worldwide
- changes in political environment (e.g.: geopolitical and technopolitical) and public opinion
- unanticipated operating results, including changes or fluctuations in crude oil, NGLs and natural gas production levels
- incorrect assessments of the value of acquisitions or divestments, or the failure to complete divestments
- failure to realize anticipated benefits of recently completed or future acquisitions

- 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
- the ability of the Corporation to achieve specific targets that are part of its ESG strategy, including those relating to GHG emissions and freshwater use reductions, as well as other climate change-related initiatives
- changes in development plans by the Corporation or third-party operators
- the ability of the Corporation to comply with debt covenants under the Credit Facilities
- the ability of the Corporation to access required capital
- changes in capital and other expenditure requirements and debt service requirements
- liabilities and unexpected events inherent in oil and gas operations, including geological, technical, drilling and processing risks, as well as unforeseen title defects or litigation
- actions of and reliance on industry partners
- uncertainties associated with estimating reserves and resources
- competition for, among other things, capital, acquisitions of reserves and resources, undeveloped lands, access to services, third party processing capacity and skilled personnel
- constraints on, or the unavailability of, adequate infrastructure, including pipeline and other transportation capacity, to deliver the Corporation's production to market, whether in the control of the Corporation or not
- the Corporation's success at the acquisition, exploitation and development of reserves and resources
- changes in tax, environmental, regulatory, or other legislation applicable to the Corporation, including those which are climate change-related, 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 and/or impact the Corporation's production and operations

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

Corporate Structure

ENERPLUS CORPORATION

The Corporation was incorporated on August 12, 2010 under the ABCA for the purposes of participating in the plan of arrangement under ABCA, pursuant to which the business of Enerplus Resources Fund, as the Corporation's predecessor, was transitioned to the Corporation on January 1, 2011. Prior thereto, the business of the Corporation was carried on by Enerplus Resources Fund and its subsidiaries as an income trust since 1986.

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

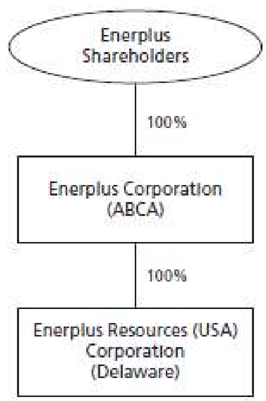
The Corporation's head offices are located at The Dome Tower, 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1, which is also its registered office, and at The US Bank Tower, 2200, 950 - 17th Street, Denver, Colorado, 80202-2805. The Common Shares are currently traded on the TSX and the NYSE under the symbol "ERF".

MATERIAL SUBSIDIARIES

As of December 31, 2021, 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, 2021 is set forth below.



General Development of the Business

DEVELOPMENTS IN THE PAST THREE YEARS

Developments in 2019 and 2020

During 2019 and early 2020, the Corporation continued to focus on maintaining a strong balance sheet and returning cash to shareholders through its monthly dividend and share repurchases. From the beginning of 2019 and through March 2020, the Corporation repurchased an aggregate of approximately 18.6 million Common Shares on the TSX and NYSE for approximately US$136.1 million.

During 2020, the onset of the COVID pandemic resulted in a sudden global economic downturn creating significant challenges for the energy industry and reduced global demand for crude oil and natural gas. In response to the decline in crude oil demand and historically low prices, Enerplus suspended its operated drilling and completions activity in North Dakota, and temporarily curtailed production from certain wells across its crude oil and natural gas liquids properties during the second quarter of 2020 to preserve cash flow. As commodity prices improved, Enerplus brought the majority of the curtailed production back online by early July 2020, reinstated its guidance and resumed limited completion activity during the fourth quarter under a lower capital spending program. The Corporation continued its monthly dividend through 2020; however, the Corporation did not renew its normal course issuer bid to preserve capital and maintain its balance sheet strength.

Developments in 2021 and 2022 to date

ACQUISITIONS & ASSET SALES

On March 10, 2021, the Corporation completed the Bruin Acquisition for approximately US$465 million, before purchase price adjustments of US$45 million, resulting in the final purchase price of approximately US$420 million. The Bruin Acquisition included approximately 24,000 BOE/day of gross production (72% tight oil, 14% NGLs and 14% natural gas) at the time of closing and was financed with the Term Facility (see "*Description of Capital Structure – Term Loan and SLL Credit Facility*" below) and equity financing completed on February 3, 2021 (see below).

On April 30, 2021, the Corporation completed the Dunn County Acquisition involving certain crude oil and natural gas assets comprised of 78,700 net acres in the Williston Basin for total cash consideration of US$312 million, before purchase price adjustments and transaction costs of US$5.2 million, resulting in the final purchase price of US$306.8 million. The Dunn County Acquisition included approximately 6,000 BOE/day of gross production (76% tight oil, 10% NGLs, and 14% natural gas) at the time of closing and was financed with cash on hand and by borrowing on the SLL Credit Facility.

On November 2, 2021, the Corporation completed the sale of its Sleeping Giant (Montana) and Russian Creek (North Dakota) interests in the Williston Basin for total cash consideration of US$115 million, before purchase price adjustments and transaction costs of US$7.2 million, resulting in the final purchase price of US$107.8 million. The Corporation will receive up to US$5 million in contingent payments if the WTI oil price averages over US$65 per barrel in 2022 and over US$60 per barrel in 2023. The divested assets included approximately 3,000 BOE/day of gross production (76% tight oil, 1% NGLs and 23% natural gas).

For a description of the Corporation's Bakken interests, see "*Business of the Corporation – Description of Properties – U.S. Crude Oil Properties*".

On February 2, 2022, Enerplus announced its plans to initiate a divestment process for its Canadian assets. If the marketing effort is successful, the Corporation expects to conclude the divestment process by mid-2022. See "*Business of the Corporation – Summary of Principal Production Locations*" and "*Business of the Corporation – Description of Properties*". The Corporation will continue to maintain its Canadian head office.

FINANCINGS

Equity Financing

On February 3, 2021, Enerplus completed a CDN$132 million equity offering with a total of 33,062,500 Common Shares issued. Net proceeds from the offering were used to finance the Bruin Acquisition and to fund increased capital expenditures on the acquired properties and other expenses in connection with the Bruin Acquisition.

Credit Facilities

Upon closing of the Bruin Acquisition on March 10, 2021, Enerplus entered into a three-year senior unsecured US$400 million Term Facility, which matures March 10, 2024. The Term Facility loan includes financial and other covenants consistent with Enerplus' SLL Credit Facility. Subsequent to December 31, 2021, Enerplus converted the Term Facility into a revolving bank credit facility with no other amendments.

On April 29, 2021 Enerplus increased and extended its senior, unsecured bank credit facility to US$900 million with a maturity date of October 31, 2025. As part of the extension of the SLL Credit Facility, the Corporation transitioned the facility to a sustainability-linked credit facility. See "*Description of Capital Structure*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*".

SHAREHOLDER RETURNS – DIVIDEND & SHARE REPURCHASES

On May 6, 2021, the Corporation announced an increase in the amount of its dividend, as well as a change in the frequency of its dividend payment from monthly to quarterly, effective with its June 2021 dividend payment. The Corporation also increased its dividend for September and December 2021, which resulted in an increase of 37%, on an annualized basis, during 2021.

The Corporation renewed its normal course issuer bid on August 16, 2021 to purchase up to 10% of the public float (within the meaning under the TSX rules) during a 12-month period. As of December 31, 2021, Enerplus has repurchased 12.9 million Common Shares for aggregate proceeds of approximately US$123.2 million. Subsequent to December 31, 2021 and up to and including February 23, 2022, the Corporation repurchased an additional 2,257,400 Common Shares for aggregate proceeds of approximately US$26.1 million.

Business of the Corporation

OVERVIEW

The Corporation's crude oil and natural gas property interests are located in the United States, primarily in North Dakota, Colorado and Pennsylvania, as well as in western Canada, primarily in the provinces of Alberta and Saskatchewan. Capital spending on these assets in 2021 totaled US$302.3 million with 85% of spending focused on the Corporation's crude oil assets in the United States.

Capital spending on the Corporation's Williston Basin and Colorado assets totaled US$256.1 million during 2021. Capital spending on the Corporation's natural gas interests in northeast Pennsylvania was US$31.0 million. Canadian crude oil waterflood properties had capital spending of US$13.3 million during 2021 and the remaining US$0.5 million was spent on various other Canadian properties. In addition, the Corporation completed the Bruin Acquisition and the Dunn County Acquisition, for a total of US$777 million, before purchase price adjustments and transactions costs, in North Dakota, and divested of its Sleeping Giant asset in Montana and certain Russian Creek assets in North Dakota for US$115 million, before purchase price adjustments and transaction costs, respectively. See "*General Developments of the Business*".

In 2021, the Corporation spent US$13.0 million on abandonment and reclamation activities,US$8.0 million of which related to the abandonment of its Tommy Lakes asset in British Columbia with the majority of the remainder spent across various other Canadian properties..

Production volumes for the year ended December 31, 2021 from the Corporation's properties consisted of 61% crude oil and NGLs and 39% natural gas, on a BOE/day basis. The Corporation's major producing properties generally have related field facilities and infrastructure to accommodate its production. The Corporation's 2021 average daily production was 92,221 BOE/day, comprised of: 42,981 bbls/day of tight oil, 3,302 bbls/day of heavy oil, 2,231 bbls/day of light and medium oil (a total of 48,514 bbls/day of crude oil), 7,823 bbls/day of NGLs and 215,304 Mcf/day of natural gas (includes 207,486 Mcf/day of shale gas). Production increased approximately 26% compared to 2020 average daily production of 73,016 BOE/day, comprised of: 30,656 bbls/day of tight oil, 3,424 bbls/day of heavy oil, 2,601 bbls/day of light and medium oil (totaling 36,681 bbls/day of crude oil), 4,499 bbls/day of NGLs and 191,014 Mcf/day of natural gas (includes 179,598 Mcf/day of shale gas). See "*Summary of Principal Production Locations*". The increase in average daily production in 2021 compared to 2020 is largely attributable to strong production from Enerplus' Bakken and Marcellus assets, including the contribution from its 2021 acquisitions, combined with Enerplus' increased capital spending in 2021 compared to the scaled back capital program and the temporary curtailment of certain crude oil production in response to the COVID global pandemic in 2020.

The Corporation's 2021 production in the United States was 92**%** of its total production, with the remaining 8**%** from Canada. Approximately 65% of the Corporation's 2021 production was operated by the Corporation, with the remainder operated by industry partners.

At December 31, 2021, the crude oil and natural gas property interests held by the Corporation were estimated to contain total proved plus probable gross reserves of 8.2 MMbbls of light and medium crude oil, 20.7 MMbbls of heavy crude oil, 299.3 MMbbls of tight oil, 56.2 MMbbls of NGLs, 19.7 Bcf of conventional natural gas and 1,367.9 Bcf of shale gas, for a total of 615.7 MMBOE. The Corporation's proved reserves represented approximately 67% of total proved plus probable reserves, with approximately 62% 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, reserves and operational information in this Annual Information Form is presented as at or, where applicable, for the year ended, December 31, 2021, (ii) all production information represents the Corporation's net production from these properties, which is calculated after deduction of royalty interests owned by others and including the Corporation's royalty interests, and (iii) except for disclosure in Appendix B, 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

For the year ended December 31, 2021, on a BOE basis, 92% of the Corporation's gross production was derived from the United States (60% from North Dakota, 29% from Pennsylvania, 2% from Montana, and 1% from Colorado) and 8% from Canada (6% from Alberta and 2% from Saskatchewan).

The following table describes the average daily gross production from the Corporation's principal producing properties and regions during the year ended December 31, 2021.

2021 Average Daily Gross 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							
North Dakota	-	-	50,429	9,139	-	56,783	69,032
Marcellus, Pennsylvania	-	-	-	-	-	197,419	32,903
Sleeping Giant, Montana(1)	-	-	1,427	-	-	3,127	1,948
DJ Basin, Colorado	-	-	1,319	151	-	1,023	1,641
Total United States	**-**	**-**	**53,175**	**9,290**	**-**	**258,352**	**105,524**
Canada(2)							
Freda Lake, Saskatchewan	2,117	-	-	-	-	-	2,117
Medicine Hat Glauconitic "C" Unit, Alberta	-	1,948	-	-	259	-	1,991
Giltedge, Alberta	-	1,628	-	-	115	-	1,647
Ante Creek, Alberta	878	-	-	95	1,106	-	1,157
Cadogan, Alberta	-	499	-	5	82	-	518
Ferrier, Alberta	35	-	-	94	2,050	-	471
Other Canada	12	20	-	219	4,100	264	979
Total Canada	**3,042**	**4,095**	**-**	**413**	**7,712**	**264**	**8,880**
Total	**3,042**	**4,095**	**53,175**	**9,703**	**7,712**	**258,616**	**114,404**

1) Assets were sold effective November 2, 2021.
2) On February 2, 2022, Enerplus announced its plans to initiate a divestment process for its Canadian assets. See "*General Development of the Business – Developments in the Past Three Years – Developments in 2021 and 2022*".

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

CAPITAL EXPENDITURES AND COSTS INCURRED

The Corporation invested US$302.3 million in its capital spending program during 2021, with 89% directed to crude oil-related projects, approximately 39% higher than its 2020 capital spending program of US$217.2 million, based on an U.S./Canadian exchange rate of 1.3416. Capital spending during 2021 was focused primarily in the Corporation's U.S. North Dakota Bakken crude oil property (with investment of US$242.5 million). The Corporation's U.S. Marcellus non-operated assets received capital investment of US$31.0 million during the year. Capital spending in Canada totaled US$13.8 million, the majority of which was spent on its waterflood assets.

In the financial year ended December 31, 2021, 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**		
	(US$ in millions)			
United States	$ 832.8	$ -	$ 0.8	$ 287.7
Canada	2.3	-	0.1	13.7
Total	$ 835.1	$ -	$ 0.9	$ 301.4

Based on a budgeted commodity price of US$75.00 per barrel WTI for crude oil, US$4.00 per Mcf NYMEX for natural gas, a Bakken differential of US$0.50 per bbl below WTI, a Marcellus differential of US$0.75 per Mcf below NYMEX and a foreign exchange rate of CDN/USD 0.79. The Corporation's 2022 exploration and development capital spending is estimated to be between US$370 to US$430 million.

The Corporation intends to finance its 2022 capital spending program with cash, internally generated cash flow and/or debt. The Corporation will review its 2022 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 2021 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, 2021, in each of Canada and the United States. Wells have been classified in accordance with the definitions of such terms in NI 51-101.

	United States				Canada			
	Development Wells		Exploratory Wells		Development Wells		Exploratory Wells	
Category of Well	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude oil wells	56	22.0	-	-	2	0.3	-	-
Natural gas wells	64	2.5	-	-	-	-	-	-
Service wells	-	-	-	-	-	-	-	-
Dry and abandoned wells	-	-	-	-	-	-	-	-
Total	120	24.5	-	-	2	0.3	-	-

For a description of the Corporation's 2022 development plans and the anticipated sources of funding these plans, see "*Capital Expenditures and Costs Incurred*", above.

OIL AND NATURAL GAS WELLS AND UNPROVED PROPERTIES

The following table summarizes, at December 31, 2021, the Corporation's interests in producing wells and wells which were drilled but not producing, but which may be capable of production in the future (the "**Non-Producing Wells**"), along with the Corporation's interests in unproved properties (as defined in NI 51-101). Although many wells produce both crude oil and natural gas, a well is categorized as a crude oil well or a natural gas well based upon the proportion of crude oil or natural gas production that constitutes the majority of production from that well.

	Producing Wells				Non-Producing Wells				Unproved Properties (acres)	
	Crude Oil		Natural Gas		Crude Oil		Natural Gas			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States										
Colorado	18	13.8	-	-	13	0.8	-	-	25,585	23,350
North Dakota	1,232	732.2	-	-	29	15.8	-	-	783	783
Pennsylvania	-	-	1,035	104.4	-	-	66	7.4	24,231	6,358
Canada										
Alberta	415	219.1	119	40.5	301	141.9	41	27.6	36,915	17,748
British Columbia	-	-	5	0.9	-	-	-	-	4,356	2,106
Saskatchewan	60	56.9	81	23.0	20	18.7	97	20.2	14,164	8,636
Total	1,725	1,022.0	1,240	168.8	363	177.2	204	55.2	106,034	58,981

The Corporation expects its rights to explore, develop and exploit on approximately 1,040 net acres of unproved properties in Canada to expire in the ordinary course, prior to December 31, 2022; no unproved properties are expected to expire in the United States. The Corporation has no material work commitments on its unproved properties and, where the Corporation determines appropriate, it can extend expiring leases by either making the necessary applications to extend or performing the necessary work.

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

DESCRIPTION OF PROPERTIES

Outlined below is a description of the Corporation's U.S. and Canadian crude oil and natural gas properties and assets, all of which are located onshore.

For additional information on contingent resources associated with certain of the Corporation's U.S. 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 Bakken in North Dakota and the Wattenberg Field in Weld County of the DJ Basin of Colorado. The Corporation spent US$256.1 million on its U.S. crude oil assets in 2021.

The Corporation has approximately 238,500 net acres of land primarily on the Fort Berthold Indian Reservation ("**FBIR**") as well as Williams and Dunn Counties. On a production basis, Enerplus operates approximately 92% of its North Dakota asset. The Corporation's Bakken properties produce a light sweet crude oil (42° API), with some associated natural gas and NGLs, from both the Bakken and Three Forks formations. Production in the Bakken averaged 57,366 BOE/day in 2021, which consisted of 41,914 bbls/day of tight oil, 7,379 bbls/day of NGLs and 48,440 Mcf/day of natural gas. During 2021, the Corporation spent US$242.5 million on its operated and non-operated assets in North Dakota, and including the assets acquired pursuant to the Bruin Acquisition and Dunn County Acquisition. This included drilling 22 net horizontal wells (18 operated and 4 non-operated), targeting both the Bakken and Three Forks formations (all of which were long lateral wells), with 42.1 net wells brought on-stream (40.1 operated and 2.0 non-operated). At the end of 2021, the Corporation had 19.9 net operated drilled uncompleted wells in North Dakota.

The Corporation holds approximately 34,700 net acres (held through leasing and farm-ins) in the DJ Basin of Colorado (northwest Weld County, Wattenberg Field). The Wattenberg Field has been producing since the 1970's and is characterized as having high recoveries and initial production rates, long reserves life and multiple stacked producing horizons. Capital investment in the DJ Basin in 2021 was US$13.6 million and focused on completing and bringing 2.6 net operated wells onstream. Average annual production for 2021 was 1,323 BOE/day (80% tight oil). At the end of 2021, the Corporation had 0.9 net operated drilled uncompleted wells in Colorado.

Overall, the Corporation's U.S. crude oil properties produced an average of 58,690 BOE/day in 2021, up 47% from 2020 primarily due to the Bruin Acquisition, Dunn Country Acquisition and well outperformance from its legacy FBIR assets.

During 2020, production was impacted by temporary curtailments due to weak commodity prices. On a BOE basis, production from U.S. crude oil properties represented 64% of the Corporation's 2021 average daily production of 92,221 BOE/day.

Approximately 226.7 MMBOE of proved plus probable reserves were added in North Dakota during 2021, including extensions, acquisitions, technical revisions and economic factors. After adjusting for 2021 gross production of 25.2 MMBOE, total proved plus probable reserves associated with this property as at December 31, 2021 were 405.2 MMBOE, approximately 99% greater than at December 31, 2020.

The Corporation had 407.4 MMBOE of proved plus probable reserves associated with its U.S. crude oil assets at December 31, 2021, representing approximately 66% of its total proved plus probable reserves.

The Corporation has entered into long-term agreements for the gathering, dehydration, processing, compression and transportation of the Corporation's share of crude oil, natural gas and NGL production from its North Dakota properties. These agreements are intended to provide the Corporation with cost certainty, and access to the U.S. Gulf Coast, where it can further access export crude oil markets. See "*Marketing Arrangements and Forward Contracts*" for further information. The Corporation has also entered into a long-term agreement for gas processing in the DJ Basin under a contract with dedicated lands, but no take or pay, or minimum commitments.

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 32,700 net acres. The Corporation's Marcellus shale gas production averaged 158 MMcf/day in 2021, representing approximately 29% of the Corporation's total average daily production of 92,222 BOE/day.

In 2021, US$31.0 million was invested in the Corporation's non-operated Marcellus interests. The Corporation participated in the drilling of 2.5 net wells and 4.5 net wells were brought on-stream. At the end of 2021, the Corporation had 1.2 net non-operated drilled uncompleted wells.

Proved plus probable Marcellus shale gas reserves were 1,051.1 Bcf as at December 31, 2021, an increase of 19.9 Bcf from 2020, and represented approximately 28% of the Corporation's total proved plus probable reserves.

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

Canadian Crude Oil Properties

OVERVIEW

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

Production from Canadian crude oil properties generates cash flow to support the Corporation's overall capital spending and cash returns to shareholders. Total Canadian crude oil waterflood properties produced an average of 5,775 BOE/day (approximately 38% light and medium oil and 57% heavy oil) during 2021, or 6% of the Corporation’s total average daily production of 92,221 BOE/day. Capital spending on Canadian crude oil properties was US$13.8 million and focused on its waterflood assets.

At December 31, 2021, there were 29.5 MMBOE, or approximately 5% of the Corporation's total proved plus probable reserves on a BOE basis associated with Canadian crude oil properties using waterflood or EOR techniques.

On February 2, 2022, Enerplus announced its plans to initiate a divestment process for its Canadian assets. See "*General Development of the Business – Developments in the Past Three Years – Developments in 2021 and 2022*".

QUARTERLY PRODUCTION HISTORY

The following table sets forth the Corporation's average daily production volumes, on a gross basis, by product type, for each fiscal quarter in 2021 and for the entire year, separately for production in Canada and the United States, and in total.

	Year Ended December 31, 2021				
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)	35,149	54,702	60,589	61,889	**53,175**
Total crude oil (bbls/day)	35,149	54,702	60,589	61,889	**53,175**
Natural gas liquids (bbls/day)	6,081	9,441	10,156	11,415	**9,290**
Total liquids (bbls/day)	41,230	64,143	70,745	73,304	**62,465**
Conventional natural gas (Mcf/day)	-	-	-	-	**-**
Shale gas (Mcf/day)	245,433	254,212	260,778	272,659	**258,352**
Total United States (BOE/day)	**82,136**	**106,512**	**114,208**	**118,747**	**105,524**
Canada					
Light and medium oil (bbls/day)	3,070	2,996	3,045	3,055	**3,042**
Heavy oil (bbls/day)	4,118	4,008	4,150	4,106	**4,096**
Tight oil (bbls/day)	-	-	-	-	**-**
Total crude oil (bbls/day)	7,188	7,004	7,195	7,161	**7,138**
Natural gas liquids (bbls/day)	391	428	411	421	**413**
Total liquids (bbls/day)	7,579	7,432	7,606	7,582	**7,551**
Conventional natural gas (Mcf/day)	8,029	6,932	7,785	8,101	**7,712**
Shale gas (Mcf/day)	508	195	109	248	**264**
Total Canada (BOE/day)	**9,002**	**8,620**	**8,922**	**8,974**	**8,880**
Total					
Light and medium oil (bbls/day)	3,070	2,996	3,045	3,055	**3,042**
Heavy oil (bbls/day)	4,118	4,008	4,150	4,106	**4,096**
Tight oil (bbls/day)	35,149	54,702	60,589	61,889	**53,175**
Total crude oil (bbls/day)	42,337	61,706	67,784	69,050	**60,313**
Natural gas liquids (bbls/day)	6,472	9,869	10,567	11,836	**9,703**
Total liquids (bbls/day)	48,809	71,575	78,351	80,886	**70,016**
Conventional natural gas (Mcf/day)	8,029	6,932	7,785	8,101	**7,712**
Shale gas (Mcf/day)	245,941	254,407	260,887	272,907	**258,616**
Total (BOE/day)	**91,138**	**115,132**	**123,130**	**127,721**	**114,404**

QUARTERLY NETBACK HISTORY

The following tables set forth the Corporation's average netbacks received for each fiscal quarter in 2021 and for the entire year, separately for gross 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, 2021				
Light and Medium Crude Oil (US$ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price[1]	$ 47.71	$ 56.71	$ 59.89	$ 68.09	**$ 58.15**
Transportation	(1.19)	(0.92)	(0.88)	(1.03)	**(1.00)**
Royalties[2]	(11.77)	(15.86)	(17.70)	(20.33)	**(16.44)**
Production costs[3]	(13.82)	(17.32)	(9.88)	(9.69)	**(12.64)**
Netback	$ 20.93	$ 22.61	$ 31.43	$ 37.04	**$ 28.07**

	Year Ended December 31, 2021				
Heavy Oil (US$ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price[1]	$ 42.83	$ 52.88	$ 56.29	$ 61.17	**$ 53.35**
Transportation	(1.22)	(1.37)	(1.16)	(1.19)	**(1.24)**
Royalties[2]	(8.31)	(11.00)	(11.61)	(14.67)	**(11.42)**
Production costs[3]	(12.02)	(16.05)	(15.71)	(14.32)	**(14.53)**
Netback	$ 21.28	$ 24.46	$ 27.81	$ 30.99	**$ 26.16**

	Year Ended December 31, 2021				
Tight Oil (US$ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States					
Sales price[1]	$ 54.99	$ 63.56	$ 68.48	$ 76.85	**$ 67.47**
Transportation	(3.31)	(2.79)	(3.45)	(4.37)	**(3.53)**
Royalties[2]	(14.87)	(17.09)	(18.48)	(20.57)	**(18.14)**
Production costs[3]	(12.62)	(11.87)	(13.83)	(11.84)	**(12.55)**
Netback	$ 24.19	$ 31.81	$ 32.72	$ 40.07	**$ 33.25**

	Year Ended December 31, 2021				
Natural Gas Liquids (US$ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
United States					
Sales price[1]	$ 28.26	$ 18.00	$ 30.31	$ 38.57	**$ 29.42**
Transportation	(1.40)	(1.49)	1.22	(0.37)	**(0.38)**
Royalties[2]	(5.46)	(3.62)	(6.54)	(7.44)	**(5.90)**
Production costs[3]	-	-	-	-	**-**
Netback	$ 21.40	$ 12.89	$ 24.99	$ 30.76	**$ 23.14**
Canada					
Sales price[1]	$ 32.49	$ 33.33	$ 42.81	$ 47.52	**$ 38.85**
Transportation	(1.39)	(2.15)	(2.08)	(1.43)	**(1.75)**
Royalties[2]	(9.31)	(9.84)	(15.72)	(16.50)	**(12.74)**
Production costs[3]	-	-	-	-	**-**
Netback	$ 21.79	$ 21.34	$ 25.01	$ 29.59	**$ 24.36**

	Year Ended December 31, 2021				
Conventional Natural Gas (US$ per Mcf)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price[1]	$ 3.16	$ 2.82	$ 3.50	$ 4.12	**$ 3.42**
Transportation	(0.89)	(1.13)	(0.94)	(0.62)	**(0.89)**
Royalties[2]	0.27	(0.06)	0.01	0.04	**0.07**
Production costs[3]	(1.37)	(1.08)	(1.69)	(3.35)	**(1.90)**
Netback	$ 1.17	$ 0.55	$ 0.88	$ 0.19	**$ 0.70**

The production associated with the Canadian conventional natural gas netback represents approximately 2% of the Corporation’s total production.

Shale Gas (US$ per Mcf)	Year Ended December 31, 2021 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
United States					
Sales price[1]	$ 2.74	$ 1.98	$ 3.02	$ 4.01	**$ 2.96**
Transportation	(0.59)	(0.55)	(0.54)	(0.55)	**(0.55)**
Royalties[2]	(0.58)	(0.46)	(0.68)	(0.94)	**(0.67)**
Production costs[3]	(0.07)	(0.07)	(0.07)	(0.06)	**(0.07)**
Netback	$ 1.50	$ 0.90	$ 1.73	$ 2.46	**$ 1.67**
Canada					
Sales price[1]	$ 2.43	$ 2.45	$ 3.03	$ 4.17	**$ 2.91**
Transportation	(0.89)	(1.13)	(0.94)	(0.62)	**(0.88)**
Royalties[2]	0.35	(3.23)	0.91	0.29	**(0.27)**
Production costs[3]	(0.21)	(0.31)	(0.47)	(0.86)	**(0.41)**
Netback	$ 1.68	$ (2.22)	$ 2.53	$ 2.98	**$ 1.35**

The production associated with the Canadian shale gas netback represents a small portion of the Corporation's total production.

Notes:

(1) Before the effects of commodity derivative instruments.

(2) Includes production taxes.

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

TAX HORIZON

The Corporation is subject to standard applicable corporate income taxes. Based on existing tax legislation, the Corporation's available tax pools, expected capital spending and forecasted net income, the Corporation does not anticipate paying material cash taxes in either Canada or the United States in 2022. These expectations may vary depending on numerous factors, including fluctuations in commodity prices, the Corporation's capital spending, changes in tax laws, and the nature and timing of the Corporation's acquisitions and divestments. As a result, the Corporation emphasizes that it is difficult to give guidance on future taxability as it operates within an industry that constantly changes. See "*Risk Factors – Changes in laws or free trade agreements, including those affecting tax, royalties and other financial and trade matters, including exports, and interpretations of those laws and trade agreements, may adversely affect the Corporation and its securityholders*".

For additional information, see Notes 2 and 15 to the Financial Statements and the information under the heading "Income Taxes" in the Corporation's MD&A, which can be found on its SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

MARKETING ARRANGEMENTS AND FORWARD CONTRACTS

Crude Oil and NGLs

The Corporation's crude oil and NGLs production is marketed to a diverse portfolio of intermediaries and end users, generally on 30-day continuously renewing contracts for crude oil in Canada, negotiated contracts ranging from 30 days up to two years for crude oil in the U.S., and yearly contracts for NGLs in Canada, where terms fluctuate with the monthly spot markets. NGLs contracts in the U.S. are linked to processing arrangements with pricing linked to the monthly spot markets. The Corporation received an average price (before transportation costs and the effects of commodity derivative instruments) of US$66.05/bbl for its crude oil and US$29.86/bbl for its NGLs for the year ended December 31, 2021, compared to US$33.30/bbl for its crude oil and US$7.79/bbl for its NGLs for the year ended December 31, 2020.

In the United States, the Corporation transports its U.S. crude oil production to its buyers by pipeline and/or truck, and may occasionally sell a portion to buyers who may utilize rail transportation (after title is transferred into the buyer's name). In 2021, the Corporation received an average price differential for its U.S. Bakken crude oil of US$2.15/bbl below WTI, compared to an average of US$5.39/bbl below WTI in 2020. The Corporation has access to firm transportation of 22,550 gross barrels per day on the Dakota Access Pipeline ("**DAPL**"), via its own contracted service and with third party capacity, on which it transports a portion of its North Dakota crude oil production to the U.S. Gulf Coast, where it can further access export crude oil markets. The Corporation's NGLs associated with its U.S. crude oil production volumes are marketed on its behalf by midstream companies in North Dakota, Montana and Colorado. See "*Risk Factors – Sales Pipelines and Rail Transportation Systems*".

In Canada, the Corporation typically transports its Canadian crude oil production to its buyers by pipeline and/or truck. The Corporation may occasionally sell a portion of its crude oil production to buyers who may use rail transportation (after title is transferred into the buyer's name). The Corporation has firm transportation capacity for approximately 820 BOE/day on average from 2022 to 2027. Additionally, the Corporation has contracted firm NGLs fractionation agreements for 1,125 bbls/day through 2027.

Natural Gas

In marketing its natural gas production, the Corporation strives for a mix of contracts and customers. In 2021, 73% of the Corporation's natural gas production originated from its non-operated Marcellus interest in northeast Pennsylvania. The Corporation delivered approximately 50% of its Marcellus production in 2021 onto the Transco Leidy Pipeline, with most of the remaining volumes delivered onto the Tennessee Gas Pipeline 300 Line in Pennsylvania. A portion was then transported to the Kentucky/Tennessee border. The Corporation has firm sales contracts for up to 59 MMcf/day of natural gas production in the Marcellus for terms of up to eight years with buyers who hold pipeline capacity on these and other pipelines in the region. The Corporation also has firm transportation agreements to transport gas within and out of the region for approximately 68 MMcf/day, with terms ending between 2022 and 2036.

The average price received by the Corporation (before transportation and the effects of commodity derivative instruments) for its natural gas in 2021 was US$2.98/Mcf compared to US$1.40/Mcf for the year ended December 31, 2020. In 2021, the Corporation received an average price differential for its U.S. Marcellus shale gas production of US$0.81/Mcf below NYMEX compared to an average of US$0.65/Mcf below NYMEX in 2020. Approximately 23% of the Corporation's natural gas production was associated natural gas production from its crude oil operations in North Dakota, Montana and the DJ Basin. The Corporation does not market these volumes directly, as they are marketed on Enerplus' behalf by midstream companies.

In Canada, the Corporation sells its natural gas production at a mix of fixed and floating prices for a variety of terms ranging from spot sales to one year or longer; the monthly sales portfolio reflects a mix of the daily and monthly market indices. Approximately 3% of the Corporation's total natural gas production originated in Canada in 2021. At December 31, 2021, the Corporation held firm service natural gas transportation contracts for its natural gas production in Canada for 2022 totalling 11 MMcf/day.

Future Commitments and Forward Contracts

The Corporation may use various types of derivative financial instruments and fixed price physical sales contracts to manage the risk related to fluctuating commodity prices. Absent such hedging activities, all of the crude oil and NGLs and the majority of natural gas production of the Corporation is sold into the open market at prevailing market prices, which exposes the Corporation to the risks associated with commodity price fluctuations and foreign exchange rates. See "*Risk Factors*". Information regarding the Corporation's financial instruments is contained in Note 17 to the Financial Statements and under the heading "*Results of Operations – Price Risk Management*" in the Corporation's MD&A, each of which is available through the internet on the Corporation's website at www.enerplus.com, on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

Oil and Natural Gas Reserves

SUMMARY OF RESERVES

All of the Corporation's reserves, including its U.S. reserves, have been evaluated in accordance with NI 51-101. Independent reserves evaluations have been conducted on properties comprising approximately 98% 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 71% 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 Colorado. McDaniel used the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2022 to prepare its report. The Corporation has evaluated the remaining 29% of the net present value of its Canadian properties using similar evaluation parameters, including the same forecast price and inflation rate assumptions utilized by McDaniel. McDaniel has reviewed the Corporation's internal evaluation of these properties.

NSAI, independent petroleum consultants based in Dallas, Texas, has evaluated all of the Corporation's reserves associated with the Corporation's properties in Pennsylvania. For consistency in the Corporation's reserves reporting, NSAI used the average of the commodity price forecasts and inflation rates of GLJ, McDaniel and Sproule as of January 1, 2022 to prepare its report.

The following sections and tables summarize, as at December 31, 2021, 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, 2020 to December 31, 2021, 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 spending, 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, 2021, using forecast price and cost cases.

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

As of December 31, 2021

	OIL AND NATURAL GAS RESERVES													
RESERVES CATEGORY	Light & Medium Oil		Heavy Oil		Tight Oil		Natural Gas Liquids		Conventional Natural Gas		Shale Gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)
Proved Developed Producing														
United States	-	-	-	-	89,263	71,850	17,950	14,458	-	-	678,336	547,004	220,270	177,475
Canada	5,585	4,616	14,099	11,970	-	-	689	567	15,140	14,598	345	328	22,954	19,642
Total	**5,585**	**4,616**	**14,099**	**11,970**	**89,263**	**71,850**	**18,640**	**15,025**	**15,140**	**14,598**	**678,681**	**547,332**	**243,223**	**197,117**
Proved Developed Non-Producing														
United States	-	-	-	-	1,863	1,503	320	259	-	-	5,730	4,642	3,138	2,536
Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**1,863**	**1,503**	**320**	**259**	**-**	**-**	**5,730**	**4,642**	**3,138**	**2,536**
Proved Undeveloped														
United States	-	-	-	-	87,475	70,011	14,937	11,953	-	-	386,089	309,964	166,760	133,625
Canada	660	557	1,513	1,285	-	-	-	-	56	50	-	-	2,183	1,849
Total	**660**	**557**	**1,513**	**1,285**	**87,475**	**70,011**	**14,937**	**11,953**	**56**	**50**	**386,089**	**309,964**	**168,943**	**135,474**
Total Proved														
United States	-	-	-	-	178,600	143,365	33,208	26,669	-	-	1,070,154	861,611	390,168	313,636
Canada	6,245	5,173	15,612	13,255	-	-	689	567	15,196	14,648	345	328	25,136	21,491
Total	**6,245**	**5,173**	**15,612**	**13,255**	**178,600**	**143,365**	**33,897**	**27,236**	**15,196**	**14,648**	**1,070,500**	**861,939**	**415,304**	**335,127**
Probable														
United States	-	-	-	-	120,746	96,717	22,102	17,706	-	-	297,339	243,965	192,404	155,084
Canada	1,917	1,551	5,079	4,210	-	-	222	196	4,481	4,329	88	84	7,980	6,693
Total	**1,917**	**1,551**	**5,079**	**4,210**	**120,746**	**96,717**	**22,324**	**17,902**	**4,481**	**4,329**	**297,427**	**244,049**	**200,384**	**161,776**
Total Proved Plus Probable														
United States	-	-	-	-	299,346	240,082	55,310	44,375	-	-	1,367,493	1,105,576	582,572	468,720
Canada	8,162	6,724	20,691	17,465	-	-	911	763	19,677	18,977	433	412	33,116	28,184
Total	**8,162**	**6,724**	**20,691**	**17,465**	**299,346**	**240,082**	**56,221**	**45,139**	**19,677**	**18,977**	**1,367,927**	**1,105,988**	**615,688**	**496,904**

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

As of December 31, 2021

	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 US$ millions)						US$/BOE
Proved Developed Producing											
United States	3,280	2,746	2,358	2,079	1,871	2,836	2,414	2,094	1,861	1,686	$13.29
Canada	398	360	305	262	229	398	360	305	262	229	$15.53
Total	**3,678**	**3,106**	**2,663**	**2,341**	**2,100**	**3,234**	**2,774**	**2,400**	**2,123**	**1,915**	**$13.51**
Proved Developed Non-Producing											
United States	58	48	41	36	32	42	36	31	27	24	$16.29
Canada	-	-	-	-	-	-	-	-	-	-	-
Total	**58**	**48**	**41**	**36**	**32**	**42**	**36**	**31**	**27**	**24**	**$16.29**
Proved Undeveloped											
United States	2,405	1,817	1,420	1,141	937	1,766	1,337	1,043	837	687	$10.63
Canada	35	22	13	7	4	35	22	13	7	4	$7.09
Total	**2,440**	**1,839**	**1,433**	**1,149**	**941**	**1,801**	**1,359**	**1,056**	**845**	**691**	**$10.58**
Total Proved											
United States	5,743	4,611	3,819	3,256	2,841	4,644	3,787	3,168	2,725	2,396	$12.18
Canada	433	382	318	269	233	433	382	318	269	233	$14.81
Total	**6,175**	**4,993**	**4,138**	**3,526**	**3,074**	**5,077**	**4,169**	**3,487**	**2,994**	**2,629**	**$12.35**
Probable											
United States	3,915	2,528	1,750	1,282	980	2,895	1,853	1,269	921	699	$11.29
Canada	205	118	76	53	40	205	118	76	53	40	$11.39
Total	**4,120**	**2,646**	**1,827**	**1,335**	**1,020**	**3,100**	**1,971**	**1,346**	**975**	**739**	**$11.29**
Total Proved Plus Probable											
United States	9,658	7,139	5,570	4,538	3,821	7,539	5,640	4,438	3,646	3,095	$11.88
Canada	638	500	394	323	273	638	500	394	323	273	$13.99
Total	**10,296**	**7,639**	**5,964**	**4,861**	**4,094**	**8,177**	**6,139**	**4,832**	**3,969**	**3,368**	**$12.00**

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, the estimated abandonment, decommissioning and reclamation costs of the Corporation, and having

regard for remaining corporate tax pools at the effective date, applicable deductions and appropriate federal, provincial and state tax rates.
(2) Calculated using net present value of future net revenue before deducting income taxes, discounted at 10% per year, and net reserves. The unit values are based on net reserves volumes.

FORECAST PRICES AND COSTS

The forecast price and cost case assumes no legislative or regulatory amendments, and includes the effects of inflation. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2022 (utilized by McDaniel, NSAI and by the Corporation in its internal evaluations for consistency in the Corporation's reserves reporting), and the following inflation and exchange rate assumptions:

	CRUDE OIL					NATURAL GAS		NATURAL GAS LIQUIDS Edmonton Par Price				
Year	WTI(1)	Edmonton Light(2)	Western Canadian Select(3)	Alberta Heavy(4)	Sask Cromer Medium(5)	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)	($Cdn/bbl)	($Cdn/MMbtu)	($US/MMbtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	(%/year)	($US/$Cdn)
2022	72.83	86.82	74.42	66.45	83.26	3.56	3.85	43.38	57.49	91.85	0.0	0.797
2023	68.78	80.73	69.17	61.90	77.45	3.21	3.44	35.92	50.17	85.53	2.3	0.797
2024	66.76	78.01	66.54	59.45	74.84	3.05	3.17	34.62	48.53	82.98	2.0	0.797
2025	68.09	79.57	67.87	60.64	76.34	3.11	3.24	35.31	49.50	84.63	2.0	0.797
2026	69.45	81.16	69.23	61.87	77.86	3.17	3.30	36.02	50.49	86.33	2.0	0.797
2027	70.84	82.78	70.61	63.11	79.42	3.23	3.37	36.74	51.50	88.05	2.0	0.797
2028	72.26	84.44	72.02	64.37	81.01	3.30	3.44	37.47	52.53	89.82	2.0	0.797
2029	73.70	86.13	73.46	65.67	82.63	3.36	3.50	38.22	53.58	91.61	2.0	0.797
2030	75.18	87.85	74.69	66.68	84.28	3.43	3.58	38.99	54.65	93.44	2.0	0.797
2031	76.68	89.61	76.19	68.02	85.97	3.50	3.65	39.77	55.74	95.32	2.0	0.797
2032	78.21	91.40	77.71	69.38	87.69	3.57	3.72	40.56	56.86	97.22	2.0	0.797
2033	79.78	93.23	79.27	70.77	89.44	3.64	3.79	41.37	57.99	99.17	2.0	0.797
2034	81.37	95.09	80.85	72.18	91.23	3.71	3.87	42.20	59.15	101.15	2.0	0.797
2035	83.00	96.99	82.47	73.63	93.05	3.79	3.95	43.05	60.34	103.17	2.0	0.797
2036	84.66	98.93	84.12	75.10	94.91	3.86	4.03	43.91	61.54	105.24	2.0	0.797
Thereafter	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	2.0	0.797

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

In 2021, the Corporation received a weighted average price (before transportation costs and the effects of commodity derivative instruments) of US$66.05/bbl for crude oil, US$29.86/bbl for natural gas liquids and US$2.98/Mcf for natural gas.

UNDISCOUNTED FUTURE NET REVENUE BY RESERVES CATEGORY

The undiscounted total future net revenue by reserves category as of December 31, 2021, 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 US$ millions)				
Proved Reserves								
United States	15,052	3,959	3,706	1,336	308	5,743	1,099	4,644
Canada	1,340	216	492	61	137	433	-	433
Total	16,392	4,175	4,198	1,397	445	6,175	1,099	5,077
Proved Plus Probable Reserves								
United States	24,897	6,637	5,853	2,367	382	9,658	2,119	7,539
Canada	1,816	301	662	77	140	638	-	638
Total	26,714	6,938	6,515	2,444	522	10,296	2,119	8,177

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, the estimated abandonment, decommissioning and reclamation costs of the Corporation, 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, 2021, 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 US$ thousands)	(US$/bbl; US$/Mcf)
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]	3,214,439	22.42
	Conventional Natural Gas (including by-products) [3]	n/a	n/a
	Shale Gas[4]	604,840	0.86
	Total	**3,819,279**	
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]	4,914,391	20.47
	Conventional Natural Gas (including by-products) [3]	n/a	n/a
	Shale Gas[4]	655,199	0.78
	Total	**5,569,590**	
Canada			
Proved Reserves	Light and Medium Oil (including solution gas and by-products)[2]	100,977	19.54
	Heavy Oil (including solution gas and by-products) [2]	198,296	14.96
	Tight Oil[2]	n/a	n/a
	Conventional Natural Gas (including by-products)[3]	18,430	1.63
	Shale Gas[3]	519	1.58
	Total	**318,222**	
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and by-products)[2]	127,885	19.04
	Heavy Oil (including solution gas and by-products) [2]	243,714	13.95
	Tight Oil[2]	n/a	n/a
	Conventional Natural Gas (including by-products)[3]	22,207	1.50
	Shale Gas[3]	614	1.49
	Total	**394,420**	
Total			
Proved Reserves	Light and Medium Oil (including solution gas and by-products) [2]	100,977	
	Heavy Oil (including solution gas and by-products) [2]	198,296	
	Tight Oil[2]	3,214,439	
	Conventional Natural Gas (including by-products) [3]	18,430	
	Shale Gas[3][4]	605,359	
	Total	**4,137,501**	
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and by-products) [2]	127,885	
	Heavy Oil (including solution gas and by-products) [2]	243,714	
	Tight Oil[2]	4,914,391	
	Conventional Natural Gas (including by-products) [3]	22,207	
	Shale Gas[3][4]	655,813	
	Total	**5,964,009**	

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 2022 in preparing the estimates of gross proved reserves and gross probable reserves is set forth below. Actual 2022 production (including from North Dakota and Marcellus properties in the separate tables below) may vary from the estimates provided by McDaniel and NSAI as the Corporation's actual development programs, timing and priorities may differ from the forecast of development by McDaniel and NSAI. Columns may not add due to rounding.

	Gross Proved Reserves							
	United States				Canada			
Product Type	Estimated 2022 Aggregate Production		Estimated 2022 Average Daily Production		Estimated 2022 Aggregate Production		Estimated 2022 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	-	Mbbls	-	bbls/day	961	Mbbls	2,632	bbls/day
Heavy Oil	-	Mbbls	-	bbls/day	1,394	Mbbls	3,820	bbls/day
Tight Oil	23,568	Mbbls	64,571	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	23,568	Mbbls	64,571	bbls/day	2,355	Mbbls	6,452	bbls/day
Natural Gas Liquids	4,037	Mbbls	11,061	bbls/day	108	Mbbls	295	bbls/day
Total Liquids	27,606	Mbbls	75,632	bbls/day	2,463	Mbbls	6,747	bbls/day
Conventional Natural Gas	-	MMcf	-	Mcf/day	2,343	MMcf	6,420	Mcf/day
Shale Gas	107,042	MMcf	293,265	Mcf/day	52	MMcf	142	Mcf/day
Total	45,446	MBOE	124,509	BOE/day	2,862	MBOE	7,841	BOE/day

	Gross Probable Reserves							
	United States				Canada			
Product Type	Estimated 2022 Aggregate Production		Estimated 2022 Average Daily Production		Estimated 2022 Aggregate Production		Estimated 2022 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	-	Mbbls	-	bbls/day	30	Mbbls	83	bbls/day
Heavy Oil	-	Mbbls	-	bbls/day	21	Mbbls	59	bbls/day
Tight Oil	2,154	Mbbls	5,901	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	2,154	Mbbls	5,901	bbls/day	52	Mbbls	142	bbls/day
Natural Gas Liquids	397	Mbbls	1,088	bbls/day	6	Mbbls	15	bbls/day
Total Liquids	2,551	Mbbls	6,989	bbls/day	57	Mbbls	157	bbls/day
Conventional Natural Gas	-	MMcf	-	Mcf/day	94	MMcf	258	Mcf/day
Shale Gas	3,134	MMcf	8,587	Mcf/day	1	MMcf	3	Mcf/day
Total	3,074	MBOE	8,421	BOE/day	73	MBOE	200	BOE/day

The tables below set forth McDaniel's and NSAI's estimated 2022 production for the Corporation's North Dakota, United States properties, 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 2022 production.

	Gross Proved Reserves							
	North Dakota				Marcellus			
Product Type	Estimated 2022 Aggregate Production		Estimated 2022 Average Daily Production		Estimated 2022 Aggregate Production		Estimated 2022 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	23,241	Mbbls	63,674	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	23,241	Mbbls	63,674	bbls/day	-	Mbbls	-	bbls/day
Natural Gas Liquids	3,998	Mbbls	10,953	bbls/day	-	Mbbls	-	bbls/day
Total Liquids	27,239	Mbbls	74,626	bbls/day	-	Mbbls	-	bbls/day
Conventional Natural Gas	-	MMcf	-	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	23,505	MMcf	64,399	Mcf/day	83,238	MMcf	228,050	Mcf/day
Total	31,156	MBOE	85,359	BOE/day	13,873	MBOE	38,008	BOE/day

	Gross Probable Reserves							
	North Dakota				Marcellus			
Product Type	Estimated 2022 Aggregate Production		Estimated 2022 Average Daily Production		Estimated 2022 Aggregate Production		Estimated 2022 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	2,121	Mbbls	5,810	bbls/day	-	Mbbls	-	bbls/day
Total Crude Oil	2,121	Mbbls	5,810	bbls/day	-	Mbbls	-	bbls/day
Natural Gas Liquids	393	Mbbls	1,077	bbls/day	-	Mbbls	-	bbls/day
Total Liquids	2,514	Mbbls	6,887	bbls/day	-	Mbbls	-	bbls/day
Conventional Natural Gas	-	MMcf	-	Mcf/day	-	MMcf	-	Mcf/day
Shale Gas	2,245	MMcf	6,150	Mcf/day	857	MMcf	2,349	Mcf/day
Total	2,888	MBOE	7,912	BOE/day	143	MBOE	391	BOE/day

FUTURE DEVELOPMENT COSTS

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

	UNITED STATES				CANADA			
	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 US$ millions)				
2022	327	315	338	326	5	5	5	5
2023	340	299	340	299	23	20	22	20
2024	347	276	348	276	14	11	16	13
2025	322	235	419	302	5	4	10	7
2026	0	-	375	246	9	6	13	8
2027	0	-	422	251	3	2	8	5
Remainder	-	-	125	70	2	-	3	1
Total	1,336	1,125	2,367	1,771	61	48	77	59

RECONCILIATION OF RESERVES

Overview

The Corporation's total gross proved plus probable reserves at December 31, 2021 were 615.7 MMBOE, an increase of 45% from year-end 2020. The Corporation's gross proved plus probable crude oil and NGLs reserves were 384.4 MMBOE and represented 62% of total proved plus probable gross reserves, an increase of 9% from year-end 2020. The Corporation replaced approximately 204% of its 2021 gross production through its exploration and development program, adding 85.0 MMBOE of proved plus probable reserves, including revisions and economic factors. Of the Corporation’s 85.0 MMBOE of proved plus probable additions, including revisions and economic factors, 69.0 MMBOE is attributed to the North Dakota properties, 15.3 MMBOE (91.9 Bcf) to the Marcellus shale gas property and 0.6 MMBOE in the Corporation’s Canadian properties.

The Corporation acquired a total of 157.7 MMBOE of proved plus probable reserves in 2021, all associated with its North Dakota properties.

In 2021, the Corporation sold its interests in the Sleeping Giant property in Montana which accounted for 9.0 MMBOE of gross proved plus probable reserves volumes after accounting for production. An additional 0.6 MMBOE of gross proved plus probable reserves were associated with minor Canadian properties which were sold in 2021.

The following tables reconcile the Corporation's gross crude oil and natural gas reserves from December 31, 2020 to December 31, 2021, by country and in total, using forecast prices and costs. Certain columns may not add due to rounding.

UNITED STATES GROSS 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, 2020	-	-	-	-	-	-	106,186	63,941	170,127	14,066	8,306	22,372
Acquisitions	-	-	-	-	-	-	62,317	53,801	116,119	11,948	9,906	21,854
Dispositions	-	-	-	-	-	-	(5,152)	(1,439)	(6,592)	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	33,074	13,703	46,777	5,494	2,304	7,797
Economic Factors	-	-	-	-	-	-	4,086	1,161	5,247	1,038	268	1,306
Technical Revisions	-	-	-	-	-	-	(2,501)	(10,421)	(12,922)	4,053	1,319	5,371
Production	-	-	-	-	-	-	(19,409)	-	(19,409)	(3,391)	-	(3,391)
December 31, 2021	**-**	**-**	**-**	**-**	**-**	**-**	**178,600**	**120,746**	**299,346**	**33,208**	**22,102**	**55,310**

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, 2020	-	-	-	929,021	244,240	1,173,261	275,089	112,954	388,043
Acquisitions	-	-	-	67,418	50,815	118,233	85,502	72,176	157,678
Dispositions	-	-	-	(11,638)	(3,078)	(14,717)	(7,092)	(1,953)	(9,045)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	122,366	39,757	162,123	58,962	22,633	81,595
Economic Factors	-	-	-	12,371	3,186	15,557	7,186	1,960	9,146
Technical Revisions	-	-	-	44,915	(37,580)	7,335	9,038	(15,366)	(6,328)
Production	-	-	-	(94,298)	-	(94,298)	(38,517)	-	(38,517)
December 31, 2021	**-**	**-**	**-**	**1,070,154**	**297,339**	**1,367,493**	**390,168**	**192,404**	**582,572**

CANADIAN GROSS 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, 2020	6,637	2,383	9,020	16,946	5,309	22,254	-	-	-	833	295	1,129
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(20)	(3)	(22)	-	-	-	-	-	-	(154)	(52)	(207)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	8	1	9	-	-	-	-	-	-	7	2	9
Economic Factors	293	23	316	549	135	684	-	-	-	45	8	53
Technical Revisions	437	(487)	(51)	(387)	(365)	(753)	-	-	-	109	(32)	78
Production	(1,110)	-	(1,110)	(1,495)	-	(1,495)	-	-	-	(151)	-	(151)
December 31, 2021	**6,245**	**1,917**	**8,162**	**15,612**	**5,079**	**20,691**	**-**	**-**	**-**	**689**	**222**	**911**

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, 2020	17,353	5,811	23,164	525	148	673	27,396	8,980	36,376
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(1,520)	(498)	(2,018)	(117)	(53)	(170)	(447)	(147)	(594)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	189	52	241	-	-	-	47	12	59
Economic Factors	1,089	188	1,277	31	10	42	1,073	200	1,273
Technical Revisions	900	(1,072)	(172)	2	(18)	(16)	309	(1,065)	(757)
Production	(2,815)	-	(2,815)	(96)	-	(96)	(3,241)	-	(3,241)
December 31, 2021	**15,196**	**4,481**	**19,677**	**345**	**88**	**433**	**25,136**	**7,980**	**33,116**

TOTAL GROSS OIL AND GAS RESERVES

TOTAL Factors	Light & Medium Oil Proved	Light & Medium Oil Probable	Light & Medium Oil Proved Plus Probable	Heavy Oil Proved	Heavy Oil Probable	Heavy Oil Proved Plus Probable	Tight Oil Proved	Tight Oil Probable	Tight Oil Proved Plus Probable	Natural Gas Liquids Proved	Natural Gas Liquids Probable	Natural Gas Liquids Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2020	6,637	2,383	9,020	16,946	5,309	22,254	106,186	63,941	170,127	14,900	8,602	23,501
Acquisitions	-	-	-	-	-	-	62,317	53,801	116,119	11,948	9,906	21,854
Dispositions	(20)	(3)	(22)	-	-	-	(5,152)	(1,439)	(6,592)	(154)	(52)	(207)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	8	1	9	-	-	-	33,074	13,703	46,777	5,501	2,306	7,807
Economic Factors	293	23	316	549	135	684	4,086	1,161	5,247	1,083	276	1,359
Technical Revisions	437	(487)	(51)	(387)	(365)	(753)	(2,501)	(10,421)	(12,922)	4,162	1,287	5,449
Production	(1,110)	-	(1,110)	(1,495)	-	(1,495)	(19,409)	-	(19,409)	(3,542)	-	(3,542)
December 31, 2021	**6,245**	**1,917**	**8,162**	**15,612**	**5,079**	**20,691**	**178,600**	**120,746**	**299,346**	**33,897**	**22,324**	**56,221**

TOTAL Factors	Conventional Natural Gas Proved	Conventional Natural Gas Probable	Conventional Natural Gas Proved Plus Probable	Shale Gas Proved	Shale Gas Probable	Shale Gas Proved Plus Probable	Total Proved	Total Probable	Total Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2020	17,353	5,811	23,164	929,546	244,388	1,173,934	302,485	121,934	424,419
Acquisitions	-	-	-	67,418	50,815	118,233	85,502	72,176	157,678
Dispositions	(1,520)	(498)	(2,018)	(11,755)	(3,131)	(14,887)	(7,539)	(2,099)	(9,638)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	189	52	241	122,366	39,757	162,123	59,008	22,645	81,653
Economic Factors	1,089	188	1,277	12,403	3,196	15,599	8,259	2,160	10,418
Technical Revisions	900	(1,072)	(172)	44,917	(37,598)	7,320	9,347	(16,431)	(7,085)
Production	(2,815)	-	(2,815)	(94,395)	-	(94,395)	(41,757)	-	(41,757)
December 31, 2021	**15,196**	**4,481**	**19,677**	**1,070,500**	**297,427**	**1,367,927**	**415,304**	**200,384**	**615,688**

The following tables reconcile the Corporation's net crude oil and natural gas reserves from December 31, 2020 to December 31, 2021, in total, using forecast prices and costs. Certain columns may not add due to rounding.

UNITED STATES NET OIL AND GAS RESERVES

TOTAL Factors	Light & Medium Oil (NET)			Heavy Oil (NET)			Tight Oil (NET)			Natural Gas Liquids (NET)		
	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, 2020	-	-	-	-	-	-	85,281	51,225	136,505	11,262	6,646	17,908
Acquisitions	-	-	-	-	-	-	50,231	43,185	93,416	9,658	7,945	17,603
Dispositions	-	-	-	-	-	-	(4,121)	(1,206)	(5,328)	10	(0)	9
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	-	-	-	26,537	10,961	37,499	4,407	1,843	6,250
Economic Factors	-	-	-	-	-	-	3,266	921	4,188	827	212	1,040
Technical Revisions	-	-	-	-	-	-	(2,141)	(8,369)	(10,510)	3,243	1,060	4,303
Production	-	-	-	-	-	-	(15,688)	-	(15,688)	(2,738)	-	(2,738)
December 31, 2021	**-**	**-**	**-**	**-**	**-**	**-**	**143,365**	**96,717**	**240,082**	**26,669**	**17,706**	**44,375**

TOTAL Factors	Conventional Natural Gas (NET)			Shale Gas (NET)			Total (NET)		
	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, 2020	-	-	-	743,206	195,640	938,846	220,410	90,477	310,887
Acquisitions	-	-	-	58,618	46,420	105,038	69,658	58,867	128,525
Dispositions	-	-	-	(9,306)	(2,586)	(11,892)	(5,663)	(1,638)	(7,300)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	98,091	31,817	129,909	47,293	18,107	65,400
Economic Factors	-	-	-	10,069	2,558	12,627	5,772	1,560	7,332
Technical Revisions	-	-	-	36,577	(29,884)	6,693	7,198	(12,289)	(5,091)
Production	-	-	-	(75,644)	-	(75,644)	(31,033)	-	(31,033)
December 31, 2021	**-**	**-**	**-**	**861,611**	**243,965**	**1,105,576**	**313,636**	**155,084**	**468,720**

CANADIAN NET OIL AND GAS RESERVES

TOTAL Factors	Light & Medium Oil (NET)			Heavy Oil (NET)			Tight Oil (NET)			Natural Gas Liquids (NET)		
	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, 2020	5,534	1,906	7,440	14,663	4,542	19,205	-	-	-	787	283	1,069
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(19)	(3)	(22)	-	-	-	-	-	-	(223)	(72)	(295)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	6	1	7	-	-	-	-	-	-	17	4	21
Economic Factors	179	21	200	259	105	364	-	-	-	83	21	103
Technical Revisions	288	(374)	(86)	(462)	(437)	(899)	-	-	-	22	(39)	(17)
Production	(814)	-	(814)	(1,205)	-	(1,205)	-	-	-	(118)	-	(118)
December 31, 2021	**5,173**	**1,551**	**6,724**	**13,255**	**4,210**	**17,465**	**-**	**-**	**-**	**567**	**196**	**763**

TOTAL Factors	Conventional Natural Gas (NET)			Shale Gas (NET)			Total (NET)		
	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, 2020	18,008	5,928	23,936	499	141	640	24,068	7,742	31,809
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(2,851)	(856)	(3,708)	(111)	(50)	(161)	(736)	(226)	(962)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	459	116	575	-	-	-	100	25	124
Economic Factors	1,851	428	2,279	(1)	(3)	(4)	829	217	1,046
Technical Revisions	35	(1,287)	(1,252)	30	(4)	27	(141)	(1,065)	(1,206)
Production	(2,853)	-	(2,853)	(89)	-	(89)	(2,628)	-	(2,628)
December 31, 2021	**14,648**	**4,329**	**18,977**	**328**	**84**	**412**	**21,491**	**6,693**	**28,184**

TOTAL NET OIL AND GAS RESERVES

TOTAL Factors	Light & Medium Oil (NET) Proved	Probable	Proved Plus Probable	Heavy Oil (NET) Proved	Probable	Proved Plus Probable	Tight Oil (NET) Proved	Probable	Proved Plus Probable	Natural Gas Liquids (NET) Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2020	5,534	1,906	7,440	14,663	4,542	19,205	85,281	51,225	136,505	12,048	6,929	18,977
Acquisitions	-	-	-	-	-	-	50,231	43,185	93,416	9,658	7,945	17,603
Dispositions	(19)	(3)	(22)	-	-	-	(4,121)	(1,206)	(5,328)	(213)	(73)	(286)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	6	1	7	-	-	-	26,537	10,961	37,499	4,424	1,847	6,271
Economic Factors	179	21	200	259	105	364	3,266	921	4,188	910	233	1,143
Technical Revisions	288	(374)	(86)	(462)	(437)	(899)	(2,141)	(8,369)	(10,510)	3,265	1,021	4,286
Production	(814)	-	(814)	(1,205)	-	(1,205)	(15,688)	-	(15,688)	(2,856)	-	(2,856)
December 31, 2021	**5,173**	**1,551**	**6,724**	**13,255**	**4,210**	**17,465**	**143,365**	**96,717**	**240,082**	**27,236**	**17,902**	**45,139**

TOTAL Factors	Conventional Natural Gas (NET) Proved	Probable	Proved Plus Probable	Shale Gas (NET) Proved	Probable	Proved Plus Probable	Total (NET) Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2020	18,008	5,928	23,936	743,705	195,781	939,485	244,478	98,219	342,697
Acquisitions	-	-	-	58,618	46,420	105,038	69,658	58,867	128,525
Dispositions	(2,851)	(856)	(3,708)	(9,417)	(2,636)	(12,053)	(6,399)	(1,864)	(8,263)
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	459	116	575	98,091	31,817	129,909	47,393	18,132	65,525
Economic Factors	1,851	428	2,279	10,067	2,555	12,622	6,601	1,777	8,378
Technical Revisions	35	(1,287)	(1,252)	36,607	(29,888)	6,719	7,057	(13,354)	(6,297)
Production	(2,853)	-	(2,853)	(75,733)	-	(75,733)	(33,661)	-	(33,661)
December 31, 2021	**14,648**	**4,329**	**18,977**	**861,939**	**244,049**	**1,105,988**	**335,127**	**161,776**	**496,904**

UNDEVELOPED RESERVES

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

Proved Undeveloped Reserves

Year[(1)]	Crude Oil Light & Medium	Heavy	Tight	NGLs	Conventional Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
2019	330	-	20,460	2,243	-	81,546	36,624
2020	-	-	9,896	1,397	-	65,091	22,141
2021	-	-	28,182	4,784	-	108,948	51,124

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

Probable Undeveloped Reserves

Year[(1)]	Crude Oil Light & Medium	Heavy	Tight	NGLs	Conventional Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
2019	150	-	17,026	2,003	-	73,529	31,434
2020	-	-	6,174	687	-	38,195	13,227
2021	-	-	12,641	2,106	-	38,135	21,103

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

The Corporation attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information, and the optimization of existing fields. The Corporation considers each of its undeveloped locations to be projects that have larger capital expenditures and, consistent with the COGE Handbook, has generally assigned development of or the commencement of significant capital expenditures on proved undeveloped locations to occur within three years (five years for resource plays) and within five years (ten years for resource plays) for probable undeveloped reserves. The Corporation has in recent years continually developed its undeveloped reserves in Canada and the United States. The Corporation intends to fund the development of its undeveloped reserves as of December 31, 2021 with cash, internally generated cash flow and/or debt. These expenditures are expected to extend the continual development of undeveloped reserves in Canada and the United States beyond two years.

In the Fort Berthold property, the Corporation has been active for the last several years in drilling and developing these undeveloped reserves, converting the associated volumes to producing reserves. The Corporation has, in the past, maintained the gross proved plus probable undeveloped location well count year over year and added undeveloped locations to replace those that were drilled in the preceding year. With the acquisition of additional properties in North Dakota and improved commodity price forecasts, the Corporation expects to increase its activity in its North Dakota properties and has increased the operated gross proved plus probable undeveloped location count from 174 locations in 2020 to 423 locations as of December 31, 2021. The conversion of the proved undeveloped locations to producing reserves is scheduled to occur continuously over the next four years and the development of the remaining probable undeveloped locations is scheduled to occur within seven years.

In 2021, the Corporation continued to participate in the development of its non-operated undeveloped reserves in the Marcellus property, converting 4.1 net proved plus probable locations to developed reserves. These converted locations were replaced with additions of 6.7 net proved plus probable undeveloped locations as of December 31, 2021. Development timing for both proved undeveloped and proved plus probable undeveloped locations is determined by the scheduling prepared by the operators of the property. In this case, development of the proved undeveloped locations is scheduled to take place over four years and the development of the probable undeveloped locations is scheduled to take place over the next seven years.

In Canada, the Corporation's drilling activity level has been modest in recent years, and in 2021 consisted of participating in the drilling of 6 gross non-operated wells in the Ferrier property, which is located in Alberta. Development of proved plus probable undeveloped locations was deferred, to recommence in 2023, due to increased development activities in the Corporation's properties in the United States. Undeveloped reserves assigned to locations in the Corporation's Canadian properties are in Cadogan, Giltedge and Medicine Hat 'Glauc C', which are located in Alberta, and the Ratcliffe property located in Saskatchewan. Enerplus anticipates there will be drilling activity in the Cadogan, Medicine Hat 'Glauc C" and Ratcliffe properties starting in 2023. Development of the Canadian proved undeveloped reserves is forecast to occur continuously over the next five years, and the development of the probable undeveloped reserves is forecast to occur over the next six 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 significant abandonment and reclamation costs associated with its reserves properties or properties with no attributed reserves, and the Corporation does not anticipate its abandonment and reclamation liabilities to negatively impact its reserves data or its ability to develop these reserves at this time. Abandonment and reclamation costs associated with surface leases, wells, undeveloped locations, facilities and pipelines for the Corporation's properties with assigned reserves in Canada and the United States have been reflected in reserves estimates.

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

PROVED AND PROBABLE RESERVES NOT ON PRODUCTION

The Corporation has approximately 3.8 MMBOE (3.1 MMBOE in its U.S. crude oil properties and 0.6 MMBOE (3.8 Bcf) in its U.S. natural gas properties) of proved plus probable reserves which are capable of production but which, as of December 31, 2021, were not on production. These reserves have generally been non-producing for periods ranging from a few months to three years. In the United States, the majority of these volumes are associated with operated wells in North Dakota (21 wells) and Pennsylvania (2 wells) that are shut-in due to pump failures or in need of a workover. All of these non-producing assets have been scheduled to recommence production by 2023.

Supplemental Operational Information

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

The Corporation has adopted the H&S Policy and the ESG Policy to articulate Enerplus' commitment to health and safety, stakeholder engagement, environmental and regulatory compliance and governance practices. These policies are high-level statements of intent that guide Enerplus' decision-making and are consistent with its values and demonstrate its goal of producing safe and socially responsible energy. The Board and the President & Chief Executive Officer are ultimately accountable for ensuring compliance with both policies. The Corporation's management and its corporate sustainability department are responsible for ensuring they are communicated and integrated across the Corporation. All employees and contractors of the Corporation are responsible for complying with the policies. The Board is responsible for overseeing the Corporation's ESG activities. Furthermore, Enerplus has identified six material ESG focus areas with accountability for each area assigned to a committee of the Board. The Board's Reserves, Safety and Social Responsibility ("**RS&SR**") Committee has responsibility for four of the six areas, including GHG emissions, water management, health and safety and community engagement, whereas the other two – culture and board constitution and culture – are overseen by the Compensation and Human Resources Committee and the Corporate Governance and Nominating Committee, respectively.

The Corporation strives to develop and operate its oil and natural gas assets in a socially responsible manner and places a high priority on protecting the health and safety of its employees, contractors and the public in the communities in which it operates, as well as preserving the quality of the environment. The Corporation also encourages active and open collaboration with its stakeholders. The Corporation has established processes and programs designed to evaluate and manage health, safety, environmental and regulatory risks, and strives for ongoing improvement in its corporate sustainability and ESG performance.

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

- Ensure its culture of accountability is applied to personal safety and the safety of others
- Proactively identify and mitigate life critical safety risks in its operations through a focus on leading indicators and incident investigations
- Set annual safety targets focused on continuous improvement and monitor performance throughout the year with the Board, leadership, employees and contractors
- Provide safety training and expect all workers to identify, report and act on all hazards
- Create and maintain an environment that supports and requires a Stop Work culture
- Partner with like-minded contractors to incorporate industry best practices into operational standards and processes to keep people safe while delivering operational excellence

The ESG Policy reiterates the Corporation's commitment to environmental, social and governance issues and states that the Corporation will:

- invest in innovative solutions to reduce GHG emissions
- increase the efficiency of energy consumption to reduce emissions intensity
- improve water and land use practices
- limit the waste we generate
- prevent and manage releases
- monitor environmental performance and provide transparent disclosure
- continuously improve environmental management system and provide resources and training to improve its capability to meet and exceed environmental commitments
- proactively comply with all applicable rules and regulations
- invest in building and sustaining positive relationships with each of its stakeholders
- continuously monitor culture via multiple qualitative tools and a quantitative survey system
- engage with community stakeholders to understand their needs and concerns and promote economic and social development in its operating areas
- support the Board's engagement and oversight of the development and execution of its ESG approach

The Corporation's commitment to building meaningful and transparent relationships with its stakeholders is embedded in the ESG Policy. In addition, it 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 published in its ESG Report and Data Tables. The Corporation uses the Global Reporting Initiative Core Standard and the Sustainability Accounting Standards Board materiality map to identify and prioritize ESG issues. In 2019, reporting and disclosure was expanded to include the International Petroleum Industry Environmental Conservation Association guidance for sustainability reporting. In 2021, disclosure was expanded again to include the publication of the Corporation’s TCFD Aligned Reporting Table. These reports discuss and summarize the Corporation’s environmental, safety, social responsibility and governance performance, along with its targets and goals, and can be found at www.enerplus.com.

The Corporation's anticipated risk management activities and ESG strategy will require climate change-related risks to be integrated into its long-range planning process, but we cannot predict what form this will ultimately take given the long-time horizons and evolving expectations. See "*Risk Factors—The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including but not limited to those which are climate change-related, as well as public opposition and activism—Climate change-related risks*".

Health and Safety

The Corporation's total combined (employee/contractor) recordable injury frequency rate 2021 was 0.55 per 200,000 worker hours, an increase from the rate of 0.16 recorded in 2020. The Corporation had an employee recordable injury frequency rate of 0.22 per 200,000 worker hours in 2021, an increase from zero per 200,000 worker hours in 2020. The Corporation's total contractor recordable injury frequency was 0.66 per 200,000 worker hours in 2021, an increase from 0.24 injuries per 200,000 worker hours in 2020. The Corporation recorded no lost-time injuries in 2021, compared to one lost-time injury recorded in 2020. The Corporation has not had employee or contractor fatalities for any of the last five years**.** As an ESG focus area, the Corporation has established a lost time injury frequency reduction target of 25%, on average, from 2020 to 2023, relative to 2019, for its employees and contractors.

Health and safety risks influence workplace practices, operating costs and the establishment of health and safety standards. In addition to integrating targets into its ESG focus areas, the Corporation continues to maintain its health and safety management system, which is designed to:

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

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

Environment

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

- Capital expenditures related to site abandonment and reclamation activities for the Corporation's Canadian and United States properties in 2021 totaled approximately US$13 million, including US$8 million on its Tommy Lakes asset and US4.6 million across other Canadian assets. The Corporation received 45 reclamation certificates from regulatory agencies in 2021 by returning sites to their previous equivalent land capability.

- Government regulators conducted 153 inspections of the Corporation’s field operations in the United States and Canada in 2021, an increase compared to the prior year’s 77 government regulator inspections. In 2020, inspections were focused on administrative compliance (not on-site visits or physical equipment inspections) due to COVID. The percentage of non-compliant inspections received by the Corporation in 2021 decreased to eight percent, compared to 25% received in 2020.

- The Corporation conducts an internal site inspection program at its U.S. and Canadian locations to proactively assess environmental, regulatory and general housekeeping items. Findings from the internal site inspection program and any action items are recorded in the Corporation’s internal reporting platforms in order to measure compliance and ensure potential issues are addressed. In addition, the Corporation completed 12 inspections at major Canadian facilities in 2021.

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

- In 2021, the Corporation completed a total of 1,163 fugitive emissions surveys for its Canadian and U.S. production pad facilities to detect losses from leaks and vents and has repaired all identified leaks. The repairs were carried out directly by the Corporation as part of its normal operations.

- Enerplus uses water in the development of its assets in Canada and the U.S. During 2020, which is the latest available data, 80% of the Corporation's water usage occurred in its Canadian operations, where 99% of the water is recycled and reused. The Corporation is exploring opportunities to reduce, reuse and recycle freshwater in its North Dakota completions operations, introducing technology to treat water in real-time on location. Enerplus reduced its freshwater usage per well completion in FBIR by 31% in 2021, compared to 23% in 2020, an improvement of 35%. The Corporation also established a 2025 goal to reduce freshwater use per well completion by 50% on a total company basis, relative to 2019.

GHG regulations have been enacted in certain states in the United States, in Saskatchewan and Alberta, and at the federal level in the U.S. and Canada. The Corporation is required to submit a report under the Canadian federal Greenhouse Gas Reporting Program ("**GHGRP**") for any facility that emitted more than 10,000 tonnes of carbon dioxide equivalent ("**CO_2e**") during 2020. One facility report was submitted in September 2021.

For its operations in the United States, the Corporation is subject to the reporting requirement under the U.S. Environmental Protection Agency (the "**U.S. EPA**") Clean Air Act and the Mandatory Reporting of Greenhouse Gases Rule. The latest of these reports was submitted to the U.S. EPA on March 31, 2021 for the 2020 operational year. For more information on the environmental regulation applicable to the Corporation, see "*Industry Conditions – Environmental Regulation*".

In 2020, Scope 1 Emissions of CO_2e were 628,686 tonnes. The Corporation expects its 2021 Scope 1 Emissions (expected to be available in the second quarter of 2022) to be higher than 2020 as a result of its acquisition of producing assets in the Bakken. Enerplus believes it is compliant with all relevant gas capture regulatory requirements. As a part of its ESG strategy, Enerplus' has set GHG emissions intensity reduction goals, based on Scope 1 Emissions and Scope 2 Emissions, as defined by the GHGRP. During 2021, the Corporation established a goal to reduce its corporate methane emissions intensity by the end of 2022 by 20%, based on the 2019 baseline. Its 2030 target of a 50% reduction in Scope 1 Emissions and Scope 2 Emissions, relative to 2019 levels, remains. Based on preliminary estimates, Enerplus expects its total Scope 1 Emissions and Scope 2 Emissions intensity in 2021, which is measured on a gross metric tonne of CO_2e per gross wellhead BOE basis, to be reduced by approximately 25%, and its methane emissions intensity to be reduced by over 20%, both relative to a 2019 baseline; positive contributions toward achieving the Corporation's 2022 and 2030 targets. The Corporation believes achieving progress toward its emissions reduction targets is possible, for example, through the installation of vapour recovery units on all new pads and retrofits on old pads, where possible, in North Dakota, as well as the replacement of intermittent and high-bleed pneumatic devices. The Corporation spent approximately US$1.5 million on this work in 2021.

In addition to the quantitative GHG emissions targets established in 2021, Enerplus began to capture and leverage ideas being generated by employees that focused on reducing its GHG emissions in order to continue to meet its ongoing environmental obligations and achieve progress toward its ESG goals. To facilitate this, the Corporation is committed to, and has budgeted a portion of its capital expenditures to ideas that get approved as active projects. To review submitted ideas, Enerplus established an internal, executive-led working committee that meets bi-weekly. This working committee also reviews the status of funded, active projects. In addition, the Board's RS&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.

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 material ESG focus areas to support this commitment and sets forth strategic goals and targets. The Corporation believes that by monitoring various lagging and leading metrics, identifying areas for improvement, and implementing strategies, processes and procedures in those material focus areas, the Corporation will continue to improve its corporate sustainability and ESG performance. For more information on the Corporation's ESG initiatives visit www.enerplus.com.

INSURANCE

The Corporation carries insurance coverage to protect its assets at the standards typical within the oil and natural gas industry. Insurance levels are determined and acquired by the Corporation after considering the perceived risk of loss and appropriate coverage, together with the overall cost. The Corporation currently purchases insurance to protect against a number of risks including, but not limited to, third party liability, property damage, business interruption, pollution and well control. In addition, liability coverage is carried for the directors and officers of the Corporation.

The Corporation commissions third-party loss prevention audits to identify and evaluate the risk exposures associated with production equipment, process operations, utility supply systems and natural hazards. The purpose of the loss prevention audits is to generate detailed loss prevention reports with risk-based recommendations for improving the overall safety and performance of the Corporation's facilities, mitigating the potential exposure to financial loss associated with property damage and production loss, and ensuring the adequacy of its relevant insurance coverage. However, due to COVID, no loss prevention audits occurred in 2021.

PERSONNEL

As at December 31, 2021, the Corporation employed a total of 435 persons, including full-time benefit employees and payroll consultants, 211 of whom were in Canada and 224 of whom were in the United States.

Description of Capital Structure

The authorized capital of the Corporation consists of an unlimited number of Common Shares, and a number of preferred shares issuable in series ("**Preferred Shares**"), which are limited to an amount equal to not more than one-quarter of the number of issued and outstanding Common Shares at the time of the issuance of any such Preferred Shares. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares. Copies of the Corporation's Articles, By-law No. 1 and By-law No. 2 were filed on January 2, 2013, June 16, 2014, and May 6, 2016, respectively, on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

COMMON SHARES

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

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

PREFERRED SHARES

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

SENIOR UNSECURED NOTES

Enerplus has issued Senior Unsecured Notes, of which US$303.8 million principal amounts were outstanding at December 31, 2021. 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	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$178.8 million	4.40 %	May 15 and November 15	May 15, 2024	Principal payments required in three equal annual installments beginning May 15, 2022

For additional information see "*Material Contracts and Documents Affecting the Rights of Securityholders*". See also Note 9 to the Financial Statements.

SLL CREDIT FACILITY AND TERM FACILITY

As at December 31, 2021, the Corporation was undrawn on its US$900 million senior unsecured, covenant-based SLL Credit Facility with a syndicate of financial institutions maturing October 31, 2025. The SLL Credit Facility incorporates ESG-linked incentive pricing terms which reduce or increase the borrowing costs by up to 5 basis points as Enerplus' sustainability performance targets ("SPT") are exceeded or missed. The SPTs are based on ESG goals focused on GHG emissions, freshwater usage and Lost Time Injury Frequency reductions, relative to respective 2019 baseline data.

Upon closing the Bruin Acquisition on March 10, 2021, Enerplus entered into a three-year senior unsecured US$400 million Term Facility. As at December 31, 2021, the Corporation had drawn US$400 million on the Term Facility, which matures March 10, 2024 and includes financial and other covenants consistent with the Corporation's SLL Credit Facility. Subsequent to December 31, 2021, Enerplus converted the Term Facility into a revolving bank credit facility with no other amendments.

For a description of the SLL Credit Facility and Term Facility, see the MD&A and Note 9 to the Corporation's Financial Statements. See also "*Material Contracts and Documents Affecting the Rights of Securityholders*".

Dividends

DIVIDEND POLICY AND HISTORY

The Corporation's board of directors is responsible for determining the dividend policy of the Corporation. The dividend policy must comply with the requirements of the ABCA, including satisfying the solvency test applicable to ABCA corporations. The Corporation currently has established a dividend policy of paying quarterly dividends to holders of Common Shares. The dividend payment dates are on or about the 15th day each March, June, September and December and the dividend record dates are on or about the last business day of the calendar month preceding the dividend payment date. **However, any decision to pay dividends on the Common Shares will be made by the Corporation's board of directors on the basis of the relevant conditions existing at such future time, and there can be no guarantee that the Corporation will maintain its current dividend policy. Dividend amounts likely will vary, and there can be no assurance as to the level of dividends that will be paid or that any dividends will be paid at all.** See "*Risk Factors – Dividends and other payments on the Corporation's Common Shares are variable*. Cash dividends paid to non-U.S. resident shareholders are converted to Canadian dollars based upon the actual exchange rate on the dividend payment date and, accordingly, certain shareholders are subject to foreign exchange rate risk on such payments.

The Corporation declared a monthly dividend of CDN$0.01 per share in 2019 and 2020. In 2021, the Corporation declared and paid a monthly divided of CDN$0.01 per share in January through May. In May of 2021, the Corporation announced a transition to a quarterly dividend of CDN$0.033 per share starting with its June dividend. The dividend was increased to CDN$0.038 per share for the dividend declared in August of 2021 and further increased to CDN$0.041 per share for the dividend declared in November of 2021. In February 2022, the Corporation began declaring dividends in U.S. dollars instead of Canadian dollars, and declared a quarterly divided of US$0.033 per share, payable on March 15, 2022.

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

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

STOCK DIVIDEND PROGRAM

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

Industry Conditions

OVERVIEW

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

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

The Corporation is required under Canada's Extractive Sector Transparency Measures Act ("**ESTMA**") to disclose certain payments made to governments of all levels, including Indigenous groups in Canada and Indian Reservations in the United States. In addition, the Corporation will be required to furnish an annual report, or an alternative report complying with Canada's ESTMA, to the SEC beginning in 2024 disclosing any payment made during the prior fiscal year by the Corporation to the U.S. government or a foreign government for the purpose of the commercial development of oil, natural gas, or minerals. These and other disclosure regulations could require us to incur significant costs, require us to disclose competitively sensitive commercial information, or cause us to violate non-disclosure laws or agreements, including those of the Indigenous groups in Canada and Native American tribes within the United States.

PRICING AND MARKETING OF CRUDE OIL AND NATURAL GAS

In the United States and Canada, producers of crude oil negotiate sales contracts directly with crude oil purchasers. Most agreements are linked to continental or global oil prices, which are set by daily, weekly and monthly physical and financial transactions for crude oil around the world. Those prices are primarily based on overall fundamentals of supply and demand. Specific prices depend, in part, on crude oil quality, prices of competing fuels, distance to markets, access to downstream transportation, the value of refined products, the supply/demand balance and other contractual terms. In the United States, the Federal Energy Regulatory Commission ("**FERC**") regulates rates and service conditions for interstate transportation of crude oil, which affect the marketing of crude oil, as well as revenues producers receive for sales of crude oil. Intrastate crude oil transportation service is also subject to regulation by some state regulatory agencies.

Producers of natural gas in the United States and Canada are free to negotiate prices and other terms with purchasers, provided export contracts meet certain criteria. In relation to U.S. exports, this would include restrictions on export licenses imposed by the United States Department of Energy, and in Canada, criteria prescribed by the Canada Energy Regulator (previously the National Energy Board) and the Government of Canada. The prices depend, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to the market, access to downstream transportation, length of contract term, seasonal factors, weather conditions, the value of refined products, the supply/demand balance and other contractual terms. In the United States, the FERC regulates rates and service conditions for interstate transportation of natural gas, 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, general market uncertainty and a variety of other factors beyond the Corporation's control. Crude oil and natural gas prices continued to be volatile during 2021 in response to a variety of factors including, among others, changes in the global supply of crude oil as a result of volatility in demand due to the ongoing COVID pandemic, as well as ongoing decisions by the Organization of Petroleum Exporting Countries ("**OPEC**") and non-OPEC members to manage production levels to achieve balance in crude oil supply and demand. See "*Risk Factors – Oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Corporation's business, results of operations or cash flows and financial condition*". In addition, crude oil and natural gas producers in some areas of North America currently receive discounted prices for their production relative to certain continental and/or international benchmark prices due to the lack of adequate egress which would allow crude oil and natural gas production to be transported and sold to national and, in some cases, international markets. See "*Risk Factors – The inability to access land, inadequately developed infrastructure, and the impact of special interest groups on either, may result in a decline in the Corporation's ability to market its oil and natural gas production*".

Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (i) to defraud using any device, scheme or artifice; (ii) to make any untrue statement of material fact or omit a material fact; or (iii) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission ("**CFTC**") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act ("**CEA**"). With regard to the use of certain transmission or transportation facilities and the Corporation's physical purchases and sales of natural gas, crude oil, or other energy commodities and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess or seek civil penalties of up to $1,388,496 per violation, per day, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Failure to comply with the federal laws and regulations governing our operations and business activities can result in the imposition of administrative, civil and criminal remedies.

ROYALTIES AND INCENTIVES

In addition to federal regulations, each U.S. state and each province in Canada has legislation and regulations which govern oil and gas holdings and land tenure, royalties, production rates, environmental protection and other matters. In all U.S. jurisdictions, producers of oil and natural gas are typically required to make annual rental payments in respect of federal, state and freehold leases until production begins. Upon commencement of production, royalties and production taxes are paid in respect of oil and natural gas produced from federal, state and freehold lands. Producers on U.S. Indian leases are required to make annual rental payments regardless of well production, in addition to other fixed fees for land improvement, on a per well basis. The applicable royalty and production tax regime is a significant factor in the profitability of oil and natural gas production. In all Canadian jurisdictions, producers of oil and natural gas are required to pay annual rentals and royalties in respect of Crown leases, and royalties and freehold production taxes in respect of oil and natural gas produced from freehold lands.

Royalties or similar payments payable on production from lands other than federal and state lands in the United States and Crown-owned lands in Canada are determined by negotiations between the freehold mineral owner and the lessee. Federal, U.S. Indian, and state royalties and production taxes in the United States, and Crown royalties in Canada, 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 state governments in the United States and the federal and provincial governments in Canada 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. However, in other instances, such royalties may be increased. For example, in November 2021, the U.S. Department of the Interior ("**DOI**") released a report with several recommendations on how to revise federal oil and gas leasing and permitting practices, including by adjusting royalty and bonding rates, prioritizing leasing in areas with known resource potential, and avoiding leasing that conflicts with recreation, wildlife habitat, conservation, and historical and cultural resources. Implementation of many of the recommendations in the DOI report will require Congressional action and we cannot predict the extent to which the recommendations may be implemented now or in the future, but restrictions on federal oil and gas activities have the potential to result in increased costs and adversely impact our operations. Approximately 36% of the Corporation's net acreage in the United States is on U.S. federal land that the U.S. federal government holds in trust.

LAND TENURE

Crude oil and natural gas located in the United States 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 Corporation's operations in North Dakota that are located on the Fort Berthold Indian Reservation ("**FBIR**") involve allottee lands, which are lands that are administered by the Bureau of Indian Affairs ("**BIA**") but owned by individual tribal 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.

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

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

ENVIRONMENTAL REGULATION

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

United States

In the United States, oil and gas operations are regulated at the federal, tribal state and local 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 U.S. EPA for operations under the *National Environmental Policy Act*. Environmental conservation and cultural and natural resources protection at the federal and state level are administered by numerous agencies under multiple statutes, codes, and regulations.

Planning, permitting and compliance related to environmental media protection and contaminants at the federal level are administered by the U.S. EPA, or by analogous state agencies whose programs have been granted primacy by the U.S. EPA. The U.S. EPA governs federal legislation, as amended from time to time, including the *Clean Air Act*, the *Clean Water Act*, the *Resource Conservation and Recovery Act* (other than oil and gas exploration and production 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, emissions limitations and setbacks (buffers) for environmental and public health protection, which are imposed by several state agencies regulating oil and gas activities. In addition to the agencies which directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, water quality, aquatic biology, wildlife, land use, transportation, noise, spills and incidents, cumulative impacts, and impacts on disproportionately impacted communities.

Additional regulations affecting the Corporation's U.S. operations include: (i) the Federal Implementation Plan for Oil and Natural Gas Well Production Facilities, FBIR (Mandan, Hidatsa, and Arikara Nations) (the "**MHA Nation**"), in North Dakota and (ii) the Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. These regulations provide emission control requirements for the Corporation's U.S. assets, as well as increased monitoring, recordkeeping, reporting and regulatory oversight. In May 2020, the Office of the Solicitor of the DOI issued an opinion (the “Missouri River Opinion”) finding that the State of North Dakota, not the MHA Nation, was the legal owner of the minerals underlying the Missouri River. The MHA Nation filed actions in two federal courts seeking to overturn the May 2020 decision. In March 2021, the DOI withdrew the Missouri River Opinion and, only recently, on February 4, 2022, the DOI issued a new opinion on the matter, stating that the minerals beneath the Missouri River riverbed located on the FBIR belong to the MHA Nation and not the state of North Dakota. The Corporation cannot predict what effect this may ultimately have on its operations.

Hydraulic fracturing is typically regulated by state oil and natural gas commissions, though federal agencies have asserted regulatory authority over certain aspects of the hydraulic fracturing process. For more information, see "*Risk Factors – The Corporation*'*s operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including but not limited to those which are climate change-related, as well as public opposition and activism*". 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 response, at least in part, to concerns from landowners about the chemical content of fracturing fluids that were being injected into oil and gas wells on their land as well as adjacent properties. FracFocus is widely accepted among the oil and gas industry and the Corporation utilizes the registry in all states and provinces in which it operates. Currently, FracFocus lists over 1,280 companies as registry participants.

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants, the costs of which could be significant. The need to obtain permits has the potential to delay the development of our oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, BLM and certain state regulators have imposed restrictions on the flaring of natural gas.

The need for an operator to flare gas primarily stems from the fact that the rate of oil and gas development in North Dakota currently outpaces the construction of gas gathering and processing infrastructure. This situation is the result of various factors, including delays in obtaining right of way approvals, which is particularly cumbersome with respect to operations taking place on FBIR due to the application of additional regulatory requirements. The Corporation is working diligently with its midstream partner and the regulators to expand gas gathering capacity and increase gas capture rates. One measure being taken is the installation of NGL processing skids which are being used to extract NGLs from gas that would have otherwise been flared. See "*Risk Factors - Higher than expected declines or curtailments in the Corporation's production due to infrastructure constraints, third party operational business practices or failures, or government regulation could have an adverse effect on results of operations or cash flows and financial condition*". The North Dakota Industrial Commission ("**NDIC**") has issued orders and pursued other regulatory initiatives to implement legally enforceable "gas capture percentage goals" targeting the capture of natural gas produced in the state. As of November 1, 2020 to date, the enforceable gas capture percentage goal is 91%. Failure of an operator to comply with the applicable goal at maximum efficiency rate may result in the imposition of monetary penalties and restrictions on production from subject wells. As of December 31, 2021, we were capturing approximately 91% of our natural gas production in North Dakota. While we were satisfying the applicable gas capture percentage goals as of December 31, 2021, there is no assurance that we will remain in compliance in the future or that such future satisfaction of such goals will not have a material adverse effect on our business and results of operations.

The NDIC has 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 Corporation has been in compliance with the NDIC conditioning standards requirements.

Other states have adopted similar or more stringent regulations for environmental protection. For example, Colorado has adopted sweeping changes to the states oil and gas law, including, among other matters, requiring the Colorado Oil and Gas Conservation Commission ("**COGCC**") to prioritize public health and environmental concerns in its decisions, instructing the COGCC to adopt rules to minimize emissions of methane and other air contaminants, and delegating considerable new authority to local governments to regulate surface impacts. In keeping with SB 19-181, the COGCC in November 2020 adopted revisions to several regulations to increase protections for public health, safety, welfare, wildlife, and environmental resources. Most significantly, these revisions establish more stringent setbacks (2,000 feet instead of the previously required 500 feet) on new oil and gas development and eliminate routine flaring and venting of natural gas at new or existing wells across the state, each subject to only limited exceptions. Some local communities have adopted, or are considering adopting, additional restrictions for oil and gas activities, such as requiring greater setbacks. Additionally, on December 17, 2021, the Colorado Air Quality Control Commission adopted regulations aimed at curbing methane emissions from oil and gas operations to include setting methane emission limits per 1,000 barrels of oil equivalent produced, more frequent inspections, and limits on emissions during maintenance.

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

British Columbia

In British Columbia, all oil and gas operations are overseen by the British Columbia Oil and Gas Commission ("**BCOGC**"), primarily through the *Oil and Gas Activities Act*. The BCOGC also oversees compliance with a variety of environmentally-related statutes, including the *Forest Act*, *Heritage Conservation Act*, *Land Act*, *Environmental Management Act* and the *Water Sustainability Act*. The Corporation has one property in British Columbia which is subject to regulatory oversight by the BCOGC. The abandonment of this property began in 2019 and the majority of work is expected to be completed by 2023. After completion of the abandonment, there will be ongoing work on reclamation and remediation through to and beyond 2024**.** All work is being completed in compliance with the governing statutory regime.

Alberta

In Alberta, the Alberta Energy Regulator ("**AER**") is the single regulator of oil and gas development in Alberta and oversees all aspects of the regulatory process, including related to exploration, construction and development, abandonment, reclamation, and remediation activities. The AER oversees compliance with the *Oil and Gas Conservation Act*, *Public Lands Act*, *Mines and Minerals Act, Water Act* and the *Environmental Protection and Enhancement Act* by oil and gas operators. The AER operates in conjunction with Alberta Environment and Parks to ensure the province's environmental, social and economic targets are met. Alberta Environment and Parks is also responsible for climate change-related regulations such as the Alberta Technology Innovation and Emissions Reduction program.

Saskatchewan

In Saskatchewan, oil and gas exploration and development is overseen by the Ministry of Energy and Resources ("**MER**"), which is responsible for the Oil and Gas Emissions Management Regulation ("**OGEMR**"), while the environmental site assessment process for certain new oil and gas development is overseen by the Saskatchewan Ministry of Environment. The MER also administers legislation including *The Crown Minerals Act, The Oil and Gas Conservation Act* and *The Pipelines Act, 1998*. Environmental regulation is governed by the Ministry of Environment pursuant to the *Saskatchewan Environmental Code*, which consolidates rules under other statutes and, among other things, prescribes applicable levels of emissions without mandating express measures to achieve such levels. Saskatchewan's Ministry of Environment provides compliance and mitigation measures aimed at protecting the environment, It is responsible for regulations that oversee provincial climate change-related initiatives such as the Output Based Performance Standard ("**OBPS**") program, which is the provincial carbon pricing system intended to encourage GHG emissions reduction initiatives.

Climate change-related legislation

Globally, the shift to a low-carbon economy continues to shape ESG practices and business strategy, in particular with respect to climate change-related actions. Climate change-related legislation at each of the provincial, state and federal levels has the potential to significantly affect the oil and gas industry regulatory environment and impose significant operational and/or financial obligations on companies.

In addition, globally, the TCFD has been working to help identify information needed by investors, lenders and credit and insurance underwriters to appropriately assess and price climate change-related risks and opportunities. Although not legislated in North America, the TCFD has developed voluntary disclosure under a singular, accessible framework specific to climate change-related actions. Four core recommendations have been presented which would apply to organizations across all sectors and jurisdictions. The four core areas of recommendation centre relate to governance, strategy, risk management and metrics and targets. An additional eleven detailed recommended disclosures have been made, along with the call for the reporting of decision-useful information in mainstream filings. Enerplus recognizes the TCFD recommended guidelines and is working toward integrating fit for purpose disclosure from the guidelines into its ESG strategy and published its first TCFD Aligned Reporting Table in connection with its 2021 ESG Report, which is available at www.enerplus.com.

Both Canada and the United States were part of the United Nations Framework Convention on Climate Change ("**UNFCCC**") meeting in Paris in 2015. A binding commitment, (the "**Paris Agreement**"), was signed by all panel countries that set a target of no more than a two-degree Celsius warming of the earth based on GHG levels in the atmosphere. This commitment to limit warming may increase provincial, state and federal GHG regulatory rigour as country-level emissions will be reviewed periodically in subsequent meetings to assess alignment with the targets agreed upon. The agreement also called for countries to submit non-binding, individually-determined emissions reduction targets every five years after 2020. Following President Biden's executive order in January 2021, the United States rejoined the Paris Agreement and, in April 2021, established a goal of reducing economy-wide net GHG emissions 50-52% below 2005 levels by 2030. Additionally, at the 26th Conference of the Parties to the UN Framework Convention on Climate Change ("**COP26**") in Glasgow in November 2021, the United States and the European Union jointly announced the launch of a Global Methane Pledge, which is an initiative committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including "all feasible reductions" in the energy sector.

Additionally, the U.S. EPA continues to enforce GHG emissions regulations pursuant to the Clean Air Act that establish a reporting program for CO_2, methane and other GHG emissions. It has also established a permitting program for certain large GHG emissions sources. There has been considerable uncertainty surrounding regulation of methane emissions in the United States, as the U.S. EPA under former President Obama's Administration published final regulations under the Clean Air Act establishing new source performance standards ("**NSPS**") for reduction of methane from certain new, modified or reconstructed oil and gas facility sources in 2016, but since that time the U.S. EPA under former President Trump's Administration has undertaken several measures to delay or restrict implementation of those standards, including publishing in September 2020 final rule policy and technical amendments to the NSPS, for stationary sources of air emissions. The policy amendments, effective September 14, 2020, notably removed the transmission and storage sector from the regulated source category and rescinded methane and VOC requirements for the remaining sources that were established by former President Obama's Administration, whereas the technical amendments, effective November 16, 2020, included changes to fugitive emissions monitoring and repair schedules for gathering and boosting compressor stations and low-production wells, recordkeeping and reporting requirements, and more. However, subsequently, the U.S. Congress approved, and President Biden signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. Additionally, in November 2021, EPA issued a proposed rule that, if finalized, would establish OOOO(b) new source and OOOO(c) first-time existing source standards of performance for methane and volatile organic compound emissions for oil and gas facilities. Operators of affected facilities will have to comply with specific standards of performance, which include leak detection using optical gas imaging and subsequent repair requirements, and reduction of emissions by 95% through capture and control systems. EPA plans to issue a supplemental proposal in 2022 containing additional requirements not included in the November 2021 proposed rule and anticipates the issuance of a final rule by the end of the year. While the United States Congress has considered numerous legislative initiatives to reduce or tax GHG emissions, to date no laws in that regard have been enacted. On a state level, some states have enacted laws concerning GHG emissions, including increased stringency of emissions standards or the imposition of regulatory markets that require certain limits on GHG emissions.

The Government of Canada is working toward the two-degree target on a sector by sector basis but has yet to finalize regulations pertaining to the oil and gas sector. As part of its commitment under the Paris Agreement, the Canadian federal government developed the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**") in 2016.

Under the Framework, the Canadian federal government requires that all jurisdictions adopt the Federal Fuel Charge or develop a carbon pricing system that is at least equivalent to the federal rate. In August 2021, the Federal government announced an increase on the national carbon pollution price, which is set at $50/tonne in 2022 with proposed increases of CDN$15 per year to reach CDN$170/tonne in 2030. Jurisdictions can comply by implementing: (i) an explicit price-based system (such as the carbon levy and performance-based emissions system adopted in Alberta), or (ii) a cap-and-trade system (which has been adopted in Ontario and Quebec). Within these programs, provinces have discretion to manage competitiveness of their trade-exposed industries. In June of 2018, the Government of Canada's federal carbon pricing system, entitled the Greenhouse Gas Pollution Pricing Act ("**GGPPA**") received royal assent. The GGPPA is only intended to act as a regulatory backstop in the event a province or territory does not otherwise implement an adequate GHG regime. Following the appeals of the Provinces of Alberta, Ontario, and Saskatchewan (in their respective provincial Courts of Appeal) regarding the constitutionality of the Federal Fuel Charge, as announced on March 25, 2021, the Supreme Court of Canada upheld the validity of the federal GGPPA establishing that federal carbon pricing, at least insofar as it serves to set a minimum carbon price in Canada, is constitutionally valid.

In addition to the above, emissions legislation came into effect on June 29, 2021 under the *Canadian Net-Zero Emissions Accountability Act* (the "**Act**"), which was established to create national GHG emissions targets to achieve net-zero by 2050, with milestone years set as 2030, 2035, 2040 and 2045. The Act codifies responsibilities for the applicable federal Ministers to set reduction targets ten years in advance of each milestone year, and create comprehensive emissions reduction plans five years in advance of each milestone year. In addition, assessment reports are to be created, prior to each milestone year, that communicate progress towards targets. On December 3, 2021, the Canadian Minister of Environment and Climate Change announced the 2030 Emissions Reduction Plan (the "**ERP**") would be tabled, as required by the Act, by the end of

March 2022. The ERP also includes an interim GHG objective for 2026. The Government of Canada has also reiterated its intention to achieve net zero by 2050 for the oil and gas industry by capping emissions at current levels and lowering the cap every five years until reaching the target in 2050. Details on these emissions caps are not yet available, but are expected later in 2022.

Since 2019, Saskatchewan has been considered a backstop province and the Federal Fuel Charge has been imposed on its industries. Saskatchewan's *Management and Reduction of Greenhouse Gas (Standards and Compliance) Regulations* were amended in October 2020 to allow for companies with stationary fuel combustion emissions of under 10,000 tonnes of CO_2e to voluntarily opt into the OBPS program in 2021. The Corporation received approval in January 2021 to participate in the OBPS program, which provides an exemption from paying the Federal Fuel Charge at its Saskatchewan facilities. The program requires an emissions intensity reduction of 1.25% each year, to culminate in a 15% reduction in total by year twelve (2033).

In October of 2019, the Government of Alberta announced its *Technology Innovation and Emissions Reduction* Regulation ("**TIER**"), which regulates large facilities emitting more than 100,000 tonnes of CO_2e annually, and allows for voluntarily opt-in. The TIER has been in force since January 1, 2020. Facilities regulated under TIER are subject to a 10% emissions intensity reduction obligation, as compared to their average emissions between 2016-2018, which provides companies operating in Alberta protection from the Federal Fuel Charge at this time. In June 2021, Enerplus purchased 4,505 TIER Fund Credits for approximately US$110,800 for its 2020 emissions compliance obligation owed under the TIER program.

In April of 2018, the Canadian federal government also issued *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations came into force on January 1, 2020. The intent of the Federal Methane Regulations is to reduce methane emissions by 40% to 45% below 2012 levels by 2025. The Federal Methane Regulations become applicable in any province or territory that chooses not to develop equivalent regulations. The provinces of Alberta and Saskatchewan achieved equivalency with the federal requirements in 2020, with the result that the relevant provincial requirements are in effect for and apply to the Corporation.

The Government of Canada reported on the effectiveness of the Federal Methane Regulations in December 2021 and confirmed that the stringency of the Federal Methane Regulations will increase. The federal government has committed to reducing oil and gas methane emissions by at least 75% below 2012 levels by 2030 and expects to release draft regulations to implement this commitment in early 2023. The Federal Methane Regulations may impose additional costs on the operations of the Corporation. The application of the Federal Methane Regulations in Alberta may change in 2023 or earlier as the federal government works to meet its desired GHG emissions reduction targets. The application of the Federal Methane Regulations in Alberta may change in 2023 or earlier as the federal government works to meet its desired GHG emissions reduction targets.

The Province of Alberta has established a methane emissions reduction goal of 45% by 2025. To achieve that, in December 2018 the AER issued prescriptive measures to reduce methane emissions by implementing design standards on new facilities, addressing venting limits from new and existing equipment, and increasing requirements regarding fugitive emission surveys and reporting. The Corporation estimates it could incur up to an additional $300,000 annually for equipment retrofits, increased measurement and reporting work, and higher frequency of fugitive leak inspections.

In May of 2010 the Province of Saskatchewan's *The Management and Reduction of Greenhouse Gases Act* ("**GHG Act**") received royal assent with only certain portions proclaimed in force on January 1, 2018. The Province of Saskatchewan has established a goal of reducing GHG emissions from the province's upstream oil and gas sector by 40% to 45% from 2015 levels by 2025. In December of 2017, the Government of Saskatchewan released a climate change-related strategy entitled *Prairie Resilience: A Made in Saskatchewan Climate Change Strategy* (the "**Strategy**") to affirm provincial regulatory jurisdiction over emissions regulation. This Strategy focuses on sector-specific approaches and climate change-related adaptation. Pursuant to the Strategy, the Province of Saskatchewan released the OGEMR, which came into effect January 1, 2019, and are applicable to entities whose potential total emissions from gas production are greater than 50,000 tonnes of CO_2e per year. In 2021, the Corporation's potential total emissions were 43,616 tonnes, which is below the criteria to be regulated under OGEMR.

The Corporation has not experienced a material adverse effect from requirements to comply with applicable environmental laws and regulations and is committed to meeting its responsibilities to protect the environment wherever it operates or holds working interests. The Corporation anticipates that this compliance may result in increased costs of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. See "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including those which are climate change-related, as well as public opposition and activism*" and "*Risk Factors – Government policy and/or regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations, including production targets, and result in increased operating and capital costs*".

WORKER SAFETY

The Corporation's operations must be carried out in accordance with safe work procedures, rules and policies contained in applicable safety legislation. Such legislation requires that every employer ensures the health and safety of all persons at any of its work sites and all workers engaged in the work of that employer. The legislation, which provides for incident reporting procedures, also requires every employer to ensure all of its employees are aware of their duties and responsibilities under the applicable legislation. Penalties under applicable occupational health and safety legislation include significant fines and incarceration. The Corporation is currently in compliance with applicable safety legislation. In addition, the Corporation has complied with all required COVID health and safety measures put in place by governments in Canada and the United States.

Risk Factors

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

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

Crude oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Corporation's business, results of operations, or cash flows and financial condition.

The Corporation's results of operations and financial condition are dependent on the prices it receives for the oil and natural gas it produces and sells. Oil and natural gas prices have fluctuated widely during recent years and may continue to be volatile in the future. These price fluctuations have been and could occur in response to a variety of factors beyond the Corporation's control, including:

- global energy supply and demand, production and regulatory policies
- actions taken by OPEC or non-OPEC members to set, maintain, or alter production levels
- the ability to export, considering regulation, taxation, and market demand, crude oil and liquefied natural gas and NGLs from North America
- geopolitical uncertainty, including for example, as a result of European energy instability; the risk of international hostile actions, as well as actions in the United States or Canada that could disrupt trade or other relations
- sustained pandemics, or epidemics, including the ongoing COVID pandemic, which disrupt economies, whether local or global, impacting supply, demand or commodity prices for crude oil, NGLs or natural gas and anticipated crude oil and natural gas price recoveries
- global and domestic economic conditions, as well as currency fluctuations
- the level of consumer demand, including demand for different qualities and types of crude oil, NGLs and natural gas
- the production and storage levels of North American natural gas and crude oil, and the supply and price of imported or exported crude oil and liquefied natural gas
- supply chain challenges and disruptions
- weather conditions
- the proximity of reserves and resources to, and capacity of, transportation facilities, and the availability of refining, processing and fractionation capacity
- the impact of world-wide energy conservation and decarbonization efforts, GHG reduction measures, and the price and availability of alternative fuels
- existing and proposed changes to government regulations and policy decisions, including moratoriums with respect thereto

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

Future declines in crude oil and/or natural gas prices, or an extended low commodity price environment, may have a material adverse effect on the Corporation's operations and cash flows, financial condition, borrowing ability, levels of reserves and resources, and the level of capital spending available for the development of the Corporation's crude oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to proceed with as part of the

Corporation's exploration or development plans or projects if commodity prices are low, thereby impacting the Corporation's production volumes. Low prices may also impact the Corporation's desire to market its production when market conditions are less satisfactory for the Corporation. Alternatively, due to regulatory or contractual obligations, the Corporation may be required to produce from or develop certain properties to fulfill its obligations despite unsatisfactory market conditions for marketing of any production therefrom, increasing the risk of financial losses. Furthermore, the Corporation may be subject to the decisions of third party operators who, independently and using different economic parameters than the Corporation, may decide to curtail or shut-in jointly owned production.

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

Higher capital or operating costs associated with the Corporation's operations will directly impact its capital efficiencies and/or decrease the amount of the Corporation's cash flow. Capital costs of completions, specifically the costs of steel, proppant, pumper services, and operating costs such as electricity, chemicals, supplies, processing charges, energy services and labour costs, are a few of the Corporation's costs that are susceptible to material fluctuation. Although the Corporation has a portion of its current capital and operating costs protected with existing agreements, changing regulatory conditions, such as potential new or revised regulations in the U.S. requiring certain raw materials, such as steel, for use on certain projects to be sourced from the U.S., or that goods and/or services be procured from specific vendors or classes of vendors on certain projects, and other supply chain challenges or disruptions may result in higher than expected supply costs for the Corporation. Additionally, the Corporation has certain service contracts tied to inflationary measure benchmarks (such as the consumer price index and WTI crude oil price), which could increase its operating costs should the benchmarks rise significantly.

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

The oil and natural gas industry is highly competitive. The Corporation competes for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled/qualified labour, access to drilling rigs, service rigs and other equipment and materials such as sand and other proppant, hydraulic fracturing pumping equipment and related skilled personnel, access to processing facilities, pipeline and refining capacity, as well as many other services, and in many other respects, with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of these organizations not only explore for, develop and produce oil and natural gas, but also conduct refining operations and market oil and other products on a world-wide basis. As a result of these complementary activities, some of the Corporation's competitors may have greater opportunities and more diverse resources to draw upon. Also, organizations that have complementary activities or are integrated may have access to, or be able to access, services or supply chain options the Corporation is not able to access, thereby limiting its ability to compete and potentially directly impacting its operational and financial results.

Service providers, including those the Corporation relies on, are also in a highly competitive environment that is impacted by worker availability, commodity prices and global supply inventories. Where worker availability is impacted by shortages, due to location or pandemic related issues, for example, some may choose or be required to streamline or discontinue their business, further reducing the supply of vendors and potentially increasing the competition for service/supplies, and thereby the costs to producers.

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

Increasing attention to ESG matters may impact the Corporation's business.

Companies across all industries are facing increasing scrutiny from stakeholders related to their ESG practices. These standards are evolving, and if the Corporation fails to comply with these standards or are perceived to have not responded appropriately to these standards, regardless of whether there is a legal requirement to do so, the Corporation may suffer from reputational damage and the business, financial condition, and/or stock price could be materially and adversely affected. Increasing attention to climate change, increasing societal expectations on companies to address climate change-related targets, and potential consumer use of substitutes to fossil-fuel energy commodities may result in increased costs, reduced demand for hydrocarbon products, reduced profits, increased investigations and litigation, and negative impacts on the Corporation's share price and access to capital markets. Increasing attention to climate change-related targets and expected actions, for example, may result in demand shifts for hydrocarbon products and additional governmental investigations and private litigation against the Corporation.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and shareholders. Such ratings are used by some investors to inform their investment and voting decisions. Additionally, certain investors use these scores to benchmark companies against their peers, and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company's sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of the Corporation's shares from consideration by certain investment funds, engagement by investors seeking to improve such scores and a negative perception of the Corporation's operations by certain investors. Additionally, to the extent ESG matters negatively impact the Corporation's reputation, it may not be able to compete as effectively to recruit or retain employees, which may adversely affect its operations.

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

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

The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities, including but not limited to those which are climate change-related, as well as public opposition and activism.

GENERAL

The oil and natural gas industry elicits concerns about climate change-related issues, as well as general public opposition to the industry. As a result, industry participants may be subject to increased public activism and, in particular, activist activity that may result in increased costs, delays or damage to facilities or operations. This may also result in negative impacts to industry supply chains, obstructing the availability of procured materials. In addition, extensive environmental regulation pursuant to local, provincial, and federal legislation in Canada and federal and state laws and regulations in the United States, may result in legislative and regulatory changes that could have an adverse effect on the Corporation, including its ability to meet its production targets. Existing and future laws and regulations may also impose additional costs on companies operating in the oil and gas industry, or significant liabilities for failure to comply with the requirements.

Concerns over climate change-related actions and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general. Any defaults by the Corporation under the applicable legislation could result in the imposition of fines or the issuance of "clean up" orders. As the form of such legislation and regulations continues to evolve, specific financial and operational outcomes are not clearly identifiable.

Generally, the business of exploration, development and production of oil and natural gas wells and facilities is subject to the risks and hazards associated with such operations. These include, but are not limited to, blowouts, fire, explosion, environmental releases (including sour gas), induced seismicity, and other safety hazards, which could result in significant damage to the Corporation's property, personal injury, loss of life, and liability to regulators or third parties. In addition, general public and government opposition toward the oil and gas industry, including the shift to global decarbonization, could reduce demand for oil and gas and, therefore, adversely affect market prices for production, as well as the financial and operating results of the Corporation.

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

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 share repurchases and/or dividends to shareholders. Enerplus has estimated the present value of its future asset retirement obligations to be approximately US$133 million at December 31, 2021 (see its Financial Statements) the majority of which it expects to incur between 2036 and 2051.

The Corporation does not establish a separate reclamation fund for the purpose of funding its estimated future environmental and reclamation obligations, therefore it cannot assure investors that it will be able to satisfy its future environmental and reclamation obligations. Further, the availability in some jurisdictions of monies collected via levies on oil and gas producers, in order to cover remediation and/or reclamation costs incurred by the Corporation on behalf of insolvent or defunct partners, may be reduced or eliminated as such funds become depleted. Should the Corporation be unable to fully fund the cost of remedying an environmental claim, the Corporation might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

CLIMATE CHANGE-RELATED RISKS

As noted, public support for climate change-related action has grown in recent years, as has the receptivity to employing new technologies to address the same. Governments in the United States, Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. At the international level, the United Nations-sponsored Paris Agreement requires nations to submit non-binding, individually-determined emissions reduction targets every five years after 2020. Following President Biden's executive order in January 2021, the United States rejoined the Paris Agreement and, in April 2021, established a goal of reducing economy-wide net GHG emissions 50-52% below 2005 levels by 2030. Additionally, at COP26 in Glasgow in November 2021, the United States and the European Union jointly announced the launch of a Global Methane Pledge, which is an initiative committing to a collective goal of reducing global methane emissions by at least 30 percent from 2020 levels by 2030, including "all feasible reductions" in the energy sector.

The major climate change-related risks are generally grouped into two categories: physical risks and transition risks. Physical risks are those that a change in climate itself could have on a business (e.g., as a result of a fire or flooding). Transition risks are broader and generally describe those risks related to the consequences of a global transition to reduced carbon. Specifically, transition risks encompass risks of regulatory and policy changes, as well as reputational concerns.

Physical Risks

Climate change may result in various physical risks, such as the increased frequency or intensity of extreme weather events (including but not limited to flooding, drought, winter storms, and wildfire) or changes in meteorological and hydrological patterns, that could adversely impact us or our contractors' operations. Such physical risks may result in damage to our facilities or infrastructure we rely on to transport our products or otherwise adversely impact our operations, such as if facilities are subject to water use curtailments in response to drought, or demand for our products, such as to the extent warmer winters reduce the demand for energy for heating purposes. Such physical risks may also impact our suppliers, which may adversely affect our operations. Extreme weather conditions can interfere with our operations and increase our costs, and damage resulting from extreme weather may not be fully insured. However, the Corporation does not believe that its current operations expose it to physical risks in a manner which materially differs from those facing other North American onshore oil and gas producers.

Transition Risks - Regulatory and Policy

The global push to meet net zero emissions targets by 2050 increases the risk of potentially burdensome regulatory and/or policy changes from governments, some of which could have a direct, negative impact on the Corporation should they impede access to service providers, lenders, insurers and the investment community. In addition, as a result of these regulations and policies, the Corporation could also be unable to obtain value for, or from, its oil and gas assets.

More specific concerns of the fossil fuels industry relate to GHG emissions, including methane, as well as water and land use. More stringent legislation or regulations in the United States and Canada, relative to other jurisdictions, including requirements to significantly reduce GHG emissions, water consumption, or setback requirements for facilities and wells, could result in increased costs and competitive disadvantages. For example, following the Trump Administration's revision of certain emissions regulations to rescind certain requirements established in 2016, the U.S. Congress approved, and President Biden signed into law a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. Additionally, in November 2021, EPA issued a proposed rule that, if finalized, would establish OOOO(b) new source and OOOO(c) first-time existing source standards of performance for methane and volatile organic compound emissions for oil and gas facilities. Operators of affected facilities will have to comply with specific standards of performance, which include leak detection using optical gas imaging and subsequent repair requirements, and reduction of emissions by 95% through capture and control systems. EPA plans to issue a supplemental proposal in 2022 containing additional requirements not included in the November 2021 proposed rule and anticipates the issuance of a final rule by the end of the year. President Biden has also made climate change a focus of his administration and has issued various executive orders calling for substantial climate change-related action, including, among other things, the increased use of zero-emissions vehicles by the United States federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate change-related risks across agencies and economic sectors. Failure to comply with such regulations and laws could result in significant penalties being imposed. In addition, a potential increase in capital spending, operating expenses, abandonment and reclamation obligations, or the loss of operating licenses, any of which may not be recoverable in the marketplace, could also result in operations or growth projects becoming less profitable, uneconomic, or result in the Corporation's inability to continue the development of its properties. See "*Industry Conditions – Environmental Regulation – Climate change-related legislation*".

There is also a risk that financial institutions will adopt, or be pressured, or required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector; both the Bank of Canada and the Federal Reserve of the United States have joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate change-related risks in the financial sector. Additionally, at COP26, the Glasgow Financial Alliance for Net Zero ("**GFANZ**") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net-zero emissions by 2050. The impact of these initiatives could require the adoption of new technologies, which could require a significant investment in capital and resources, or result in additional costs if climate change-related targets are not achieved, therefore negatively impacting the Corporation's results and economics.

At COP26 many countries announced further expanded global climate goals and targets. Given the commitments made by Canada and the U.S., the Corporation may be subject to significant changes in government policy, resulting in reduced investment if it does not comply, or unplanned spending, which could impact its operations and financial condition. In addition, should policies put in place result in permanent, significant reductions in the demand for fossil fuels, commodity prices could be negatively impacted and result in asset impairment charges, or stranded assets. Although these policies could materially impact the Corporation, it is not possible for the Corporation to quantify or estimate such impact due to the current lack of clarity around policy changes and requirements currently, as well as the timing of the same.

For a more detailed discussion on regulatory risks for the Corporation, please see "*Supplemental Operational Information*" and "*Industry Conditions – Environmental Regulation*".

Transition Risks – Reputational

The Corporation is working to develop a climate strategy by 2023 through a phased approach that delivers key components in 2021 and 2022. This strategy will address climate change-related risks and opportunities for the Corporation. Examples of progress achieved in 2021 towards the goal include the implementation of solutions to improve emissions forecasting and integrating emissions into long-range planning. In addition, these initiatives have led to the initial development of a power strategy which, at this early stage incorporates electrification of certain facilities, the goal of which will be to further reduce emissions and improve the emission efficiencies of existing power sources when grid power is not available. The Corporation's objective is to be a responsible operator—in the eyes of its shareholders, employees, contractors, regulators, lenders, communities and the general public, and this includes being responsive to climate change-related issues. However, despite its best intentions, activities undertaken directly by the Corporation or its employees in operating its business, or by others in industry, could adversely affect the Corporation's reputation. For example, there has been an increase in activist activity in Canada and the United States, including threats of culpability, and legal action against other oil and gas producers, as well as public opposition to fossil fuels and the oil and gas industry in which the Corporation operates due to negative public perceptions related to pipeline operator incidents, unpopular expansions or new projects, none of which are necessarily controlled by the Corporation but have the potential to impact the Corporation given the industry-linked association. A number of parties have sought to bring suit against certain oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. See "*— The inability to access land, inadequately developed infrastructure, and the impact of special interest groups on either, may result in a decline in the Corporation's ability to market its oil and natural gas production*".

If the reputation of the Corporation, or the oil and gas industry in general, is diminished, it could result in: the loss of employees, or revenue; delays in regulatory approvals; increased operating, capital, financing, insurance and regulatory costs; reduced shareholder confidence and negative stock price movement; negative relationships with Indian Reservations and Indigenous groups; or a loss of public support in general.

GHG Emissions and Targets

Among other sustainability goals, the Corporation has established a 2030 GHG emissions intensity reduction target of 50% for Scope 1 Emissions and Scope 2 Emissions (based on a 2019 baseline year). The Corporation's ability to lower GHG emissions on both an absolute basis and in respect of its 2030 emissions intensity reduction target is subject to numerous risks and uncertainties, and the Corporation's actions taken to implement these objectives may also expose it to certain additional and/or heightened financial and operational risks. A reduction in GHG emissions intensity relies on, among other things, the Corporation's ability to implement and improve energy efficiency at all facilities, future development and growth opportunities, development and deployment of new technologies and a focus on a reduction in flaring. In the event that the

Corporation is unable to implement these strategies and technologies as planned without negatively impacting its expected operations or business plans, or in the event that such strategies or technologies do not perform as expected, the Corporation may be unable to meet its GHG emissions intensity reduction targets or goals on the current timelines, or at all.

While the Corporation may create and publish voluntary disclosures regarding ESG matters from time to time, certain statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. Additionally, while we have announced, and may in the future announce, various targets in an attempt to improve our ESG profile, we cannot guarantee that we will be able to meet any such targets or that such targets or offerings will have the intended results on our ESG profile, including, but not limited to, as a result of unforeseen costs, consequences, or technical difficulties associated with such targets.

In addition, achieving the Corporation's GHG emissions intensity reductions target and goals could require significant capital expenditures and resources, with the potential that the costs required to achieve such target and goals materially differ from the Corporation's original estimates and expectations, which differences may be material. In addition, while the intent is to improve efficiency and reduce flaring, the shift in resources and focus towards GHG emissions reduction could have a negative impact on the Corporation's operating results. The overall final cost of investing in and implementing a GHG emissions intensity reduction strategy and technologies in furtherance of such strategy, and the resultant change in the deployment of the Corporation's resources and focus, could have a material adverse effect on the Corporation's business, financial condition and results of operations. While we may receive pressure from certain investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals or policies, we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

RISKS RELATING TO FRACTURING

The Corporation utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated 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 fluids and the volume of fluid used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations, the ability of such water to be recycled, and induced seismicity associated with fracturing. The U.S. and Canadian governments, including certain U.S. state and Canadian provincial governments, may review aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in certain of the jurisdictions in which the Corporation operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. However, governmental authorities in jurisdictions where the Corporation does not currently operate have either implemented or considered temporary moratoriums on hydraulic fracturing until further studies can be completed. In particular, President Biden issued an executive order suspending new leasing activities, but not operations under existing leases, for oil and gas exploration and production on non-Indian federal lands pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices that take into consideration potential climate and other impacts associated with oil and gas activities on such lands and waters. Although the federal court for the Western District of Louisiana issued a preliminary injunction against the leasing pause, in response to the executive order, the federal government and a coalition of environmental organizations are appealing this decision and the Department of Interior has issued a report recommending various changes to the federal leasing program, though many such changes would require Congressional action. The Corporation's operations in most jurisdictions require permits from one or more governmental agencies in order to perform drilling and completion activities and conduct other regulated activities. In the United States, such permits are typically issued by state agencies, but U.S. federal and local governmental permits may also be required. In addition, some of the Corporation's drilling and completion activities in the United States may take place on U.S. federal land or Native American lands, requiring leases and other approvals from the U.S. federal government or Native American tribes to conduct such drilling and completion activities. Under certain circumstances, U.S. federal agencies may refuse to approve new leases for hydrocarbon exploration and development on federal lands, and may refuse to grant or delay approvals required for development of existing leases. To the extent that the Corporation's operations in certain areas of the United States are restricted, delayed for varying lengths of time or cancelled, such developments may have a material adverse effect on the Corporation's results of operations and financial condition. President Biden may pursue additional executive orders, new legislation and regulatory initiatives to further implement his regulatory agenda. Additionally, certain environmental and other groups have suggested that additional federal, provincial, territorial, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process. Claims have been made that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity, particularly where operators are in proximity to pre-existing faults. See "*Industry Conditions – Royalties and Incentives*".

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

The Corporation may not realize the anticipated benefits of its acquisitions, divestments, or other corporate transactions.

From time to time, the Corporation may acquire additional oil and natural gas properties and related assets, or may acquire other corporate entities. 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/or integrating the acquired assets, properties and business into the Corporation's business. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of current or future acquisitions. The risk factors set forth in this Annual Information Form relating to the oil and natural gas business and the operations, reserves and resources of the Corporation apply equally in respect of any future properties, assets or business 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 assets, properties or business that it acquires.

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

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

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

The Corporation may also from time to time undertake other corporate actions or transactions which the directors and management of the Corporation believe are in the best interests of the Corporation. Any of the acquisitions, dispositions or other corporate actions may 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 the process. Although certain substantial acquisitions, business combinations or other corporate transactions, such as a potential re-domicile of the Corporation to another jurisdiction or a share consolidation, for example, could also be subject to approval by a certain majority of the Corporation’s shareholders, the Corporation may not achieve the intended or anticipated favourable results of such actions and may result in adverse consequences to certain or all of the Corporation’s stakeholders, including its shareholders.

Government policy and/or regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations, including production targets, 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, and other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, the imposition of specific drilling obligations, the imposition of production curtailments, control over the development and abandonment of fields (including restrictions on production), restrictions on the combustion of natural gas and possibly expropriation or cancellation of contract rights. See "*Industry Conditions*". To the extent the Corporation fails to comply with applicable government regulations or regulatory approvals, the Corporation may be subject to compliance and enforcement actions that are either remedial, which are intended to fix the non-compliance and any related impacts, or punitive, which are intended to deter future non-compliance. Such actions include fines or fees, notices of non-compliance, warnings, orders, administrative sanctions, and prosecution. In addition, obstructive tactics which could prevent certain measures from being voted upon in the United States legislature, or any government action resulting in a prolonged government shutdown, may impact the Corporation as a result of its inability to obtain regulatory and other approvals.

Government regulations may be changed from time to time in response to economic, political, or socioeconomic conditions. The Corporation's entry into new jurisdictions and its adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. U.S. federal and state and Canadian federal and provincial governments continue to scrutinize emissions, as well as the usage and disposal of chemicals and water used in fracturing procedures in the oil and gas industry; certain states have called for bans on oil and gas drilling using hydraulic fracturing. More activity by the Corporation on Indian lands in the United States, or lands held by Indigenous groups in Canada, may also increase compliance obligations under tribal or local rules. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations, or the modification of existing regulations affecting the crude oil and natural gas industry could negatively impact the development of oil and gas properties and assets, reduce demand for, or restrict the supply of, crude oil and natural gas production, or impose increased costs on oil and gas companies, any of which could have a material adverse impact on the Corporation.

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

Recent changes in U.S. administration may affect trade between other countries, including Canada.

There is uncertainty regarding U.S. support for existing treaty and trade relationships with other countries, including Canada, as evidenced by President Biden's executive order on January 20, 2021 revoking the permit for the Keystone XL Pipeline. Implementation by the U.S. government of new legislative or regulatory policies could impose additional costs on the Corporation, decrease demand for the Corporation's products, or otherwise negatively impact the Corporation, which may have a material adverse effect on the Corporation's business, financial condition and operations. In addition, this uncertainty may adversely impact (a) the ability or willingness of Canadian companies to transact business with companies such as the Corporation; (b) the Corporation's profitability; (c) regulation affecting the U.S. and Canada; (d) global stock markets (including the TSX); and (e) general global economic conditions. All of these factors are outside of the Corporation’s control, but may nonetheless lead the Corporation to adjust its strategy in order to compete effectively in global markets.

The inability to access land or use existing infrastructure, or adequately develop infrastructure, including as a result of the impact of special interest groups, may result in a decline in the Corporation's ability to operate and market its oil and natural gas production.

The Corporation's business depends in part upon the ability to access its lands to operate, as well as the availability, proximity, and capacity of oil and natural gas gathering systems, pipelines and/or rail transportation systems and processing facilities to provide access to markets for its production. U.S. federal and state, as well as Canadian federal and provincial regulation of oil and natural gas production and processing and transportation could adversely affect the Corporation's ability to produce and market crude oil, natural gas and NGLs. Special interest groups and/or social instability could prevent access to leased land or continue its opposition to infrastructure development, at either the regulatory or judicial level, including the ongoing matters with respect to DAPL (which are before the United States Supreme Court ("**SCOTUS**")), resulting in operational delays, or even cancellation of construction of the required infrastructure or the shutdown of already operating infrastructure projects, any of which frustrate the Corporation’s ability to operate, produce and market its products. In addition, the assets of the Corporation are concentrated in regions with varying levels of government regulations, or under tribal or local rules that could result in the imposition of a limit or ban on shipping of commodities by truck, pipeline or rail.

OIL AND NATURAL GAS GATHERING SYSTEMS

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

The pace at which producer or midstream companies can construct adequate gathering infrastructure to capture the natural gas associated with the development of crude oil and NGLs properties may have an impact on the Corporation's ability to increase crude oil production in its producing regions. Additionally, as exploration and drilling in these regions increases, the amount of natural gas being produced by the Corporation and others could exceed the capacity of the various gathering pipelines available in those areas. If these constraints remain unresolved, the Corporation's ability to transport its production to sales pipelines in these regions may be impaired and could adversely impact the Corporation's production volumes or realized prices in these areas. In the United States, the distinction between federally unregulated natural gas gathering facilities and FERC-regulated natural gas transmission pipelines under the Natural Gas Act ("**NGA**") has been the subject of extensive litigation and may be determined by the FERC on a case-by-case basis. Consequently, the classification and regulation of gathering facilities that we transport our product on could change based on future determinations by the FERC, the courts or the United States Congress. If these gas gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates we pay for service on the affected facilities.

SALES PIPELINES AND RAIL TRANSPORTATION SYSTEMS

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

A portion of the Corporation's production from the Williston Basin is delivered either directly or indirectly for transport to DAPL. Although the Corporation's products may be delivered for transport to other pipelines, a shutdown of DAPL or any other significant pipeline providing transportation services from the Williston Basin may adversely impact the Corporation's ability to obtain sufficient capacity on those pipelines at an effective cost. In 2016, several Sioux tribes filed a lawsuit in the United States District Court for the District of Columbia ("**District Court**") challenging authorizations issued by the United States Army Corps of Engineers ("**USACE**") to DAPL for operations near the Missouri River. In July 2020, the District Court vacated the USACE's grant of an easement to DAPL and issued an order requiring DAPL to be shut down and emptied of oil by August 5, 2020, pending an Environmental Impact Statement ("**EIS**") for the pipeline. However, this order was stayed by the Court of Appeals for the District of Columbia in early August, pending the outcome of the appeals process. On January 26, 2021, the Court of Appeals for the District of Columbia affirmed the vacatur of the easement and the requirement to prepare an EIS but declined to require the pipeline to shut down while the EIS is prepared. The Court of Appeals implored the USACE to promptly consider if and how it may deal with the vacatur of the easement and left open the possibility for the USACE to order the pipeline shut in for lack of an easement. USACE has formerly stated that it considers the presence of the pipeline without an easement to constitute an encroachment on federal land but USACE has not pursued an enforcement action with regards to this alleged encroachment. In June of 2021, the District Court rejected a request to enjoin the operation of the pipeline due to the lack of an easement and DAPL continues to operate pending the outcome of the ongoing EIS process, which is estimated to be completed no later than November 2022. In September 2021, DAPL requested SCOTUS hear an appeal on the lower court's decision to require the EIS and on the vacatur of the USACE permit. On February 22, 2022 SCOTUS denied certiorari, declining to hear the appeal. The Corporation is unable to determine the outcome or the impact on DAPL in the future. However, any future ruling or regulatory decision that restricts the availability of pipeline capacity in the Williston Basin may have a material adverse effect on the Corporation.

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

ACCESS TO PROCESSING FACILITIES

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

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

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

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

Should production for the industry, or specifically for any of the Corporation’s products, be hampered by pipeline capacity, government policy and regulations, or third party business practices, or supply chain shortages, regional commodity prices may become volatile. In some cases, alternate shipping methods, such as rail for crude oil, may be used and could result in higher costs and lower netbacks. In addition, the continuing production from a property, and to some extent the marketing of that production, is dependent upon the abilities of the operators of the Corporation's properties. A significant portion of the Corporation's production is from properties operated by third parties. This results in significant reliance on third party operators in both the operation, which may include decisions to curtail production or obtain adequate goods and services, and the ability to develop such properties as planned.

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

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

As a result of the foregoing, the Corporation may be required to curtail or shut-in production, which could damage a reservoir and potentially prevent the Corporation from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. In addition, 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.

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 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 cash dividends to its shareholders may be reduced.

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

The Corporation's business activities, both geographically and with a focus on exploration and development of unconventional reservoirs, may draw increased attention from shareholder activists who oppose the strategy of the Corporation, including its operation of the business, its plans for development and its capital allocation decisions, which could have an adverse effect on market value. In addition, such activists could become shareholders with significant influence or control, specifically to meet activist objectives. 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 or inadequate governance), title, contractual and environmental matters (including those that are climate change-related). In addition, the Corporation may, from time to time, be subject to material disputes, mediation, arbitration and litigation involving counterparties and other stakeholders the Corporation interacts with, directly or indirectly, in the ordinary course of conducting its business.

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

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

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

Tax laws, including those that may affect the taxation of the Corporation, or other laws or government incentive programs relating to the oil and gas industry generally, may be changed, or interpreted in a manner that adversely affects the Corporation and its securityholders. Canadian, U.S. and foreign tax authorities having jurisdiction over the Corporation (whether as a result of the Corporation's operations or its financing structures), may change or interpret applicable tax laws, treaties or administrative positions in a manner which is detrimental to the Corporation or its securityholders. Tax authorities may disagree with how the Corporation calculates its income for tax purposes. The Corporation may be subject to additional taxation (direct or indirect, including carbon tax, goods and services tax, or sales tax), levies or royalty payments imposed by government and tribal authorities with jurisdiction over its properties. The Corporation has income and other tax filings that are subject to audit and potential reassessment which may impact the Corporation's tax liability. The Corporation believes appropriate provisions for current and deferred income taxes have been made in its Financial Statements; however, it is difficult to predict the outcome of audit findings by tax authorities. These findings may increase the amount of its tax liabilities and be detrimental to the Corporation. In addition, the USMCA came into force on July 1, 2020, which negotiated certain changes to NAFTA that impacts merchandise commerce activities after it came into effect. This could lead to the imposition of additional duties and tariffs, or other changes that could negatively impact the Corporation's business.

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, its information assets and/or critical infrastructure may be subject to technopolitical or cyber security risks.

The Corporation is subject to a variety of information technology and system risks as 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, the growing use of the digital space could increase technopolitical risks (example, by monitoring/intercepting phones and communications, or surveilling/locating persons of interest) further increasing the risk of a breach of its security measures, which could result in a loss of material and confidential information and/or have a negative impact on its reputation, result in a breach of privacy laws, and/or disrupt 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. See also – "*The increased acceptance of, or reliance on new technology may lead to financial losses or reputational issues*"**.**

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

Declines or continued volatility in crude oil and natural gas prices may result in a significant reduction in earnings or cash flow, which could lead the Corporation to increase amounts drawn under the SLL 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 SLL Credit Facility, or significant reductions to proved reserves may result in the Corporation breaching its debt covenants under the Credit Facilities and Term Facility (when in place). 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 or Term Facility. Failure to comply with debt covenants, or negotiate relief, may result in the Corporation's indebtedness under the Credit Facilities or Term Facility 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, Term Facility and any replacement credit facility may not provide sufficient liquidity.

Although the Corporation believes that its existing Credit Facilities and Term Facility 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 and Term Facility may not be sufficient for future operations, or the Corporation may not be able to renew its SLL Credit Facility or Term Facility or obtain additional financing on attractive economic terms, if at all. The Term Facility matures March 10, 2024. The SLL Credit Facility is generally available on a four-year term, extendable each year with a bullet payment required at the end of four years if the facility is not renewed. The Corporation renewed its SLL Credit Facility in 2021, incorporating ESG-linked incentive pricing terms, and if the SPTs are not met, may result in higher future borrowing costs. The SLL Credit Facility currently expires on October 31, 2025. There can be no assurance that such a renewal will be available on favourable terms or that all the current lenders under the facility will participate or 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 SLL Credit Facility or to renew its commitment in respect of such SLL Credit Facility, or failure by the Corporation to obtain replacement financing or financing on favourable terms, may have a material adverse effect on the Corporation's business and operations. In addition, dividends to shareholders may be eliminated, as repayment of debt under the Credit Facilities and Term Facility has priority over dividend payments by the Corporation to its shareholders. See "*General Developments of the Business" and* "*Description of Capital Structure".*

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, 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 these risks, nor are all these risks insurable. The Corporation may become liable for damages arising from events against which it cannot insure, or against which it may elect not to insure because of high premium costs, or other reasons. While the Corporation has both safety and environmental policies in place to protect its operators and employees, and to meet regulatory requirements in areas where they operate, any costs incurred to repair, damage, or pay liabilities would adversely affect the Corporation's financial position, including the amount of funds that may be available for development programs, debt repayments, or dividend payments to shareholders.

The Corporation's portfolio of investment projects may expose it to increased operational and financial risks.

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

Lower crude oil and natural gas prices and higher costs increase the risk of write-downs of the Corporation's crude oil and natural 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 are limited to the estimate of future taxable income resulting from existing properties. The Corporation estimates future taxable income based on before-tax future net revenue from proved plus probable reserves, undiscounted, using forecast prices, and adjusted for other significant items affecting taxable income. The amount by which the gross deferred tax assets exceed the estimate of future taxable income will be charged to net income. A previously recorded valuation allowance can be reversed if the estimate of future taxable income increases. When commodity prices are low or declining, there remains a risk for additional write-downs under U.S. GAAP. There is also risk for future impairment when the fair value of acquired assets is significantly higher than the calculated value of the assets using 12-month trailing commodity prices, as required for under U.S. GAAP. While these write-downs would not affect cash flow, the charge to earnings may be viewed unfavourably in the market. Additional write-downs may lead to the Corporation breaching its covenants under the Credit Facilities and Term Facility (when in place), 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".*

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

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

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

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

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

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

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

Reserves and resources estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil, natural gas and NGLs prices and operating costs. Market price fluctuations of commodity prices may render uneconomic the recovery of certain categories of petroleum or natural gas. Moreover, short-term factors may impair the economic viability of certain reserves or resources in any particular period. With commodity prices remaining volatile, there is a risk for write-downs under U.S. GAAP. See "*Risk Factors – Lower crude oil and natural gas prices and higher costs increase the risk of write-downs of the Corporation's crude oil and natural gas properties and deferred tax assets*". Write-downs may lead to the Corporation breaching its covenants under the Credit Facilities and Term 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*".

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

In addition to the potential delays in payment by purchasers of oil and natural gas to the Corporation or to the operators of the Corporation's properties (and the delays of those operators in remitting payment to the Corporation), payments between any of these parties or any counterparties to contracts (including the Corporation's risk management, marketing, purchase and sale agreements, supplier and service contract counterparties) may also be delayed, or result in default due to, among other things:

- substantial or extended declines in oil, NGLs and natural gas prices
- capital or liquidity constraints experienced by such parties, including restrictions imposed by lenders
- accounting delays or adjustments for prior periods
- shortages of, or delays in, obtaining qualified personnel or equipment, including drilling rigs and completions services
- delays in the sale or delivery of products, or delays in the connection of wells to a gathering system
- adverse weather conditions, such as freezing temperatures, storms, flooding and premature thawing

- blow-outs or other accidents
- title defects
- recovery by the operator of expenses incurred in the operation of the properties, or the establishment by the operator of reserve funds for these expenses

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

The Corporation could lose its 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" ("**FPI**") status under U.S. securities laws on an annual basis at the end of its second quarter. While the Corporation currently qualifies as an FPI, it could lose its FPI status in the future. If the Corporation were to lose its status as an FPI it would be required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country. In addition, if the Corporation loses its FPI status, it would be required to report as a U.S. domestic issuer and be subject to other U.S. securities laws applicable to U.S. domestic issuers. The regulatory and compliance costs to the Corporation under U.S. securities laws as a U.S. domestic issuer may be significantly greater than the costs the Corporation incurs as a foreign private issuer. For example, as a U.S. domestic issuer, the Corporation would be required to file periodic reports and registration statements with the SEC on U.S. domestic issuer forms, which are more detailed and extensive in certain respects than the forms available to the Corporation as a foreign private issuer. The Corporation would also be required to report its oil and gas reserves and production information in accordance with applicable U.S. disclosure requirements. Such conversion and modifications would involve additional costs and may restrict the Corporation's access to capital markets for a period of time until it has satisfied SEC reporting requirements. In addition, the Corporation may lose its ability to rely upon exemptions from certain corporate governance requirements on U.S. stock exchanges that are available to FPIs, which could also increase its costs.

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

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

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

Technologies are often employed to assist, augment, automate or provide autonomous intelligence, which results in reduced reliance on human intervention and/or decision-making. Information technology ("**IT**") and cyber risks, including cyberattacks, data breaches, cyber extortion and similar compromises, are significant risks due to the Corporation's reliance on the internet to conduct day-to-day business activities, its technological infrastructure, and its use of third-party service providers. Additionally, use of personal devices by employees, vendors or other third parties can create further avenues for potential cyber-related incidents, as the Corporation has limited control over the use and safety of these devices. IT and cyber risks have increased since the COVID pandemic, with cybercriminals taking advantage of remote working environments to increase malicious activities, creating more threats for cyberattacks, including phishing emails, malware-embedded mobile apps that purport to track COVID infection rates, and targeting of vulnerabilities in remote access platforms. Furthermore, the adoption of emerging technologies, such as cloud computing, artificial intelligence and robotics, call for continued focus and investment to manage risks effectively. Although the Corporation actively manages its exposure to these risks, it may not be able to fully prevent events resulting in business interruptions, service disruptions, financial loss, theft of intellectual property and confidential information, litigation, enhanced regulatory attention and penalties, as well as reputational damage which would have an adverse effect and, therefore, may increase the Corporation's risk of financial or reputational loss; any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. See also — *"The Corporation's information assets and critical infrastructure may be subject to cyber security risks".*

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

For the year ended December 31, 2021, the Corporation elected to change its reporting currency from Canadian dollars to U.S. dollars since the majority of its crude oil and natural gas properties are in the U.S., and to facilitate a more direct comparison to other U.S. exploration and development companies. Transactions denominated in foreign currencies are translated to the functional currency of the entity (Canadian dollars for the Corporation’s Canadian entities and U.S. dollars for its U.S. entities) using the exchange rate prevailing at the date of the transaction and then translated to U.S. dollars for reporting purposes. As a result, transactions of Canadian entities are affected by the exchange rate between the U.S. and Canadian dollar, Canadian denominated receipts and payments and Canadian dollar cash dividend payments. The Corporation may from time to time use derivative instruments to manage a portion of its foreign exchange risk, as described in Note 17 to the Corporation's Financial Statements.

Court rulings and regulatory regimes on the liability surrounding abandonment and reclamation obligations of oil and gas companies may adversely affect the Corporation.

In the U.S., oversight of reclamation and remediation activities, including those that relate to orphan wells, is administered through the respective state oil and gas agencies. The levies in the U.S. are based on production and operators are required to maintain reclamation bonds for the wells and/or fields in which they operate.

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

The Corporation is currently subject to regulation by the AER under the Licensee Liability Rating Program and the Large Facility Liability Management Program. Under this regime, if a licensee's deemed liabilities exceed its deemed assets (as calculated pursuant to the programs), it must reduce its liabilities or provide the AER with a security deposit. Failure to do so may restrict the licensee's ability to transfer licenses or result in enforcement action by the AER.

On July 30, 2020, the Government of Alberta announced a new and more holistic Liability Management Framework that would replace the current regime. Much of this Framework will be implemented through AER "Directive 088: Licensee Life-cycle Management" which came into force on December 1, 2021 and will replace the AER's current Licensee Liability Rating Program when it is fully implemented in 2022. The Liability Management Framework introduces several new programs and assessments relative to the life cycle of the Corporation's energy assets that are regulated by the AER, including the new licensee capability assessment, the Licensee Management Program, the Inventory Reduction Program (including mandatory annual closure spend targets or security requirements associated with inactive wells), security collection requirements and an expanded mandate for the OWA.

Both British Columbia and Saskatchewan have somewhat similar liability management regimes to the one formerly in place in Alberta and, like Alberta, are in the process of implementing changes to make those regimes more robust. These regimes and changes may impact the Corporation's ability to transfer its licences, approvals or permits in the course of a divestment, and may result in increased costs and delays or require changes to or abandonment of projects and transactions.

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

As a result of the decision in Redwater, lenders may reduce the availability of credit to oil and gas issuers that utilize secured loans, thereby negatively affecting the financial capacity of such issuers, including potential partners and counterparties of the Corporation. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Corporation, and the associated A&R liabilities in determining whether to provide credit, may require borrowers to adhere to more stringent A&R-related operational covenants, and may increase the cost of providing credit.

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

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

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

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

Although the Corporation currently intends to continue to return cash to shareholders with a quarterly dividend payment and/or share repurchases, investor returns may change from time to time due to changes in the amount of the cash dividend paid or shares repurchased. Commencing in February 2022, cash dividends are declared in U.S. dollars and are converted to Canadian dollars and foreign denominated currencies, as applicable, at the spot exchange rate on the dividend payment date. Consequently, certain investors are subject to foreign exchange risk. To the extent that the U.S. dollar strengthens with respect to their currency, the amount of the dividend may be reduced when converted to shareholders' home currency. In addition, shareholders may be subject to withholding taxes in accordance with tax treaties or domestic tax law changes, as determined by shareholder residency.

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

- the Corporation's operational and financial performance, including fluctuations in the quantity of the Corporation's oil, NGLs and natural gas production and the sales price that the Corporation realizes for such production (after hedging contract receipts and payments)
- fluctuations in the costs to produce oil, NGLs and natural gas, including royalty burdens, and costs to administer and manage the Corporation and its subsidiaries
- the amount of cash required or retained for debt service or repayment
- amounts required to fund capital spending and working capital requirements
- access to equity markets
- foreign currency exchange rates and interest rates
- the risk factors set forth in this Annual Information Form

The decision whether to pay dividends and the amount of any such dividend is subject to the discretion of the board of directors of the Corporation, which regularly evaluates the Corporation's dividend policy, and the solvency test requirements of the ABCA. In addition, the level of dividends per Common Share will be affected by the number of outstanding Common Shares and other securities that may be entitled to receive cash dividends or other payments. Dividends may be increased, reduced or suspended entirely depending on the Corporation's operations and the performance of its assets. The market value of the Common Shares may deteriorate if the Corporation is unable to meet dividend expectations in the future, and that deterioration may be material.

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

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

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

Circumstances may arise where directors and officers of the Corporation are directors or officers of other companies involved in the oil and gas industry which are in competition to the interests of the Corporation. Directors are required to abstain from voting on matters when they are in conflict. Employees, including officers, are not permitted to partake in activities that do not support the best interests of the Corporation. Where employee conflicts exist, they are to be provided in writing to the People & Culture Department, which discloses all conflicts to General Counsel. See "*Directors and Officers – Conflicts of Interest*" and the Corporation's Code of Business Conduct at www.enerplus.com.

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

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

Market for Securities

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

The following table sets forth certain trading information for the Common Shares on the TSX and the NYSE for 2021.

	TSX Trading			NYSE Trading		
Month	**High (CDN$)**	**Low (CDN$)**	**Volume**	**High (US$)**	**Low (US$)**	**Volume**
January	4.90	3.94	32,493,275	3.88	3.07	10,681,785
February	6.82	3.96	51,919,052	5.42	3.10	15,578,284
March	7.22	5.94	40,950,447	5.82	4.71	12,305,635
April	7.05	6.09	21,311,123	5.68	4.83	9,365,893
May	8.40	6.62	23,573,927	6.62	5.39	7,717,240
June	9.28	8.06	24,657,352	7.54	6.51	8,051,432
July	9.14	7.17	17,287,292	7.50	5.61	7,772,329
August	7.88	6.12	24,534,151	6.44	4.78	9,401,833
September	10.31	7.30	31,426,992	8.14	5.76	9,014,799
October	12.08	10.02	30,336,412	9.77	7.90	7,443,549
November	13.70	11.45	39,549,950	10.81	9.19	8,267,304
December	13.75	11.11	32,822,388	11.18	8.59	11,605,955

Directors and Officers

DIRECTORS OF THE CORPORATION

The directors of the Corporation are elected by the shareholders of the Corporation at each annual meeting of shareholders. All directors serve until the next annual meeting or until a successor is elected or appointed or until the director is removed at a meeting of shareholders. The name, municipality of residence, year of appointment as a director of the Corporation and principal occupation for the past five years for each current director of the Corporation are set forth below.

Name and Residence	Director Since	Principal Occupation for Past Five Years
Hilary A. Foulkes(1)(6) Calgary, Alberta, Canada	February 2014	Corporate director and Senior Advisor to Tudor Pickering Holt & Co. Canada.
Judith D. Buie(2)(3)(5)(8) Houston, Texas, United States	January 2020	Corporate director and oil and gas industry advisor. Prior thereto, Ms. Buie was Co-President and Senior Vice President Engineering for RPM Energy Management LLC from 2012 to 2017.
Karen E. Clarke-Whistler(3)(4)(5) Toronto, Ontario, Canada	December 2018	Corporate director and consultant providing ESG advisory services. Prior thereto, Chief Environment Officer at TD Bank Group until her retirement in 2018.
Ian C. Dundas Calgary, Alberta, Canada	July 2013	President & Chief Executive Officer of Enerplus.
Robert B. Hodgins(3)(4)(7) Calgary, Alberta, Canada	November 2007	Mr. Hodgins has held a part-time, non-officer position of Senior Advisor, Investment Banking at Canaccord Genuity Corp. since September 2018 and has been an independent businessman since November 2004.
Susan M. MacKenzie(4)(5) Calgary, Alberta, Canada	July 2011	Corporate director. Prior thereto, independent consultant from 2010 to 2015.
Jeffrey W. Sheets(2)(4) Houston, Texas, United States	December 2017	Corporate director. Prior thereto, Executive Vice President and Chief Financial Officer of ConocoPhillips Company from October 2010 to February 2016.
Sheldon B. Steeves(2)(5) Calgary, Alberta, Canada	June 2012	Corporate director.

Notes:

1. Chair 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 Jeffrey W. Sheets as Chair, Judith D. Buie and Sheldon B. Steeves.
3. The Corporate Governance & Nominating Committee is currently comprised of Robert B. Hodgins as Chair, Judith D. Buie and Karen E. Clarke-Whistler.
4. The Compensation & Human Resources Committee is currently comprised of Susan M. MacKenzie as Chair, Robert B. Hodgins, Karen E. Clarke-Whistler and Jeffrey W. Sheets.
5. The Reserves, Safety & Social Responsibility Committee is currently comprised of Sheldon B. Steeves as Chair, Judith D. Buie, Karen E. Clarke-Whistler and Susan M. MacKenzie.
6. Ms. Foulkes was a director of Parallel Energy Trust ("Parallel"), a Canadian-based oil and gas trust, which commenced proceedings in the Court of Queen's Bench of Alberta, under the Companies' Creditors Arrangement Act (Canada) on November 9, 2015. Ms. Foulkes ceased to be a director of Parallel on March 1, 2016. Parallel filed an assignment in bankruptcy and proceedings under the CCAA were terminated in March 2016.
7. Mr. Hodgins was a director of Skope Energy Inc. ("Skope") from December 15, 2010 to February 19, 2013. On November 12, 2012, Skope was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the CCAA to implement a restructuring which was approved by the required majority of Skope's creditors. The restructuring was sanctioned by the Court of Queen's Bench of Alberta in February 2013.
8. Ms. Buie is was a director of Sundance Energy Australia Ltd., and subsequently Sundance Energy Inc. ("Sundance") from February 2019 through April 2021, a US-based oil and gas company, which filed for voluntary Chapter 11 protection in the U.S. Bankruptcy Court for the Southern District of Texas on March 9, 2021. The filing was initiated with the support of Sundance's lenders under a prepackaged plan of reorganization. Sundance emerged on April 23, 2021 from Chapter 11 bankruptcy as a privately held independent E&P based in Denver.

OFFICERS OF THE CORPORATION

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

Name and Residence	Office	Principal Occupation for Past Five Years
Ian C. Dundas Calgary, Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of the Corporation.
Jodine J. Jenson Labrie Calgary, Alberta, Canada	Senior Vice-President & Chief Financial Officer	Senior Vice-President & Chief Financial Officer of the Corporation.
Wade D. Hutchings Denver, Colorado, United States	Senior Vice-President, Chief Operating Officer	Senior Vice-President & Chief Operating Officer of the Corporation since February 11, 2020. Prior thereto, Senior-Vice President, Exploration & Production at Devon Energy Corporation from 2017 to 2019. Prior thereto, President, Alaska and Regional Vice-President, Mid-Continent at Marathon Oil.
Garth R. Doll Calgary, Alberta, Canada	Vice-President, Marketing	Vice-President, Marketing of the Corporation since February 2019. Prior thereto, Manager, Marketing of the Corporation.
Terry S. Eichinger Calgary, Alberta, Canada	Vice-President, Drilling, Completions & Operations Support	Vice-President, Drilling, Completions & Operations Support since June 2020. Prior thereto, Vice-President, U.S. Operations & Engineering of the Corporation since September 2018. Prior thereto, Senior Manager, U.S. Operations & Engineering of the Corporation.
Nathan D. Fisher Denver, Colorado, United States	Vice-President, United States Business Unit	Vice-President, United States Business Unit since June 2020. Prior thereto, Vice-President, U.S. Development & Geosciences of the Corporation.
Daniel J. Fitzgerald Calgary, Alberta, Canada	Vice-President, Business Development	Vice-President, Business Development of the Corporation.
John E. Hoffman Calgary, Alberta, Canada	Vice-President, Digital Technology & Corporate Sustainability	Vice-President, Digital Technology & Corporate Sustainability of the Corporation since February 2022. Prior thereto, Vice-President, Canadian Assets & Corporate Sustainability since June 2020. Prior thereto, Vice-President, Canadian Operations.
David A. McCoy Calgary, Alberta, Canada	Vice-President, General Counsel & Corporate Secretary	Vice-President, General Counsel & Corporate Secretary of the Corporation.
Shaina B. Morihira Calgary, Alberta, Canada	Vice-President, Finance	Vice-President, Finance of the Corporation since February 2018. Prior thereto, Corporate Controller of the Corporation.

COMMON SHARE OWNERSHIP

As of February 22, 2022, the directors and officers of the Corporation named above beneficially own, or control or exercise direction over, directly or indirectly, an aggregate of 1,006,971 Common Shares, representing approximately 0.41% of the outstanding Common Shares as of that date.

CONFLICTS OF INTEREST

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

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

AUDIT & RISK MANAGEMENT COMMITTEE DISCLOSURE

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

Legal Proceedings and Regulatory Actions

The Corporation is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Corporation's favour, the Corporation does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Corporation may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operations or liquidity. Notwithstanding the above, the Corporation is aware of a class action filed in Fort Berthold Tribal Court in November 2017 as Civil Action No. 2017-0505 against the Corporation and fifteen other companies operating on the FBIR (the "**Action**"). The plaintiffs in the Action are members of the Three Affiliated Tribes who own mineral interests on the FBIR and allege that, among other things, the defendant companies have committed trespass and failed to pay royalties properly. They seek judgement against the defendant group for $585 million in damages, $500 million in punitive damages, and disgorgement of the value of oil and gas produced from the plaintiffs' property. The Corporation believes the claim, as against the Corporation, is without merit.

Interest of Management and Others in Material Transactions

To the knowledge of the directors and executive officers of the Corporation, none of the directors or executive officers of the Corporation and no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of the Corporation's securities, nor any associate or affiliate of any of the foregoing, has had any material interest, direct or indirect, in any transaction with the Corporation since January 1, 2019 or in any proposed transaction that has materially affected or is reasonably expected to materially affect the Corporation.

Material Contracts and Documents Affecting the Rights of Securityholders

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

Copies of the following documents entered in the normal course of business and relating to the Credit Facilities have been filed on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov:

- Amended and Restated Agreement relating to the SLL Credit Facility (April 29, 2021);
- Amended and Restated Revolving Facility (February 24, 2022)
- Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2012 (SEDAR – May 23, 2012; EDGAR – May 24, 2012); and
- 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.

- the Articles of Amalgamation (January 2, 2013), and
- By-law No. 1 of the Corporation (June 16, 2014); and By-law No. 2 of the Corporation (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 prepared estimates of contingent resources attributable to the Corporation's North Dakota properties, 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 date of the NSAI Report, the designated professionals of NSAI, as a group, beneficially owned, directly or indirectly, no outstanding Common Shares.

KPMG LLP ("**KPMG**") was appointed as the auditors of the Corporation on May 31, 2017 and have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations, and also that they are independent accountants with respect to the Corporation under all relevant U.S. professional and regulatory standards.

Transfer Agent and Registrar

The transfer agent and registrar for the Common Shares is TSX Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario. American Stock Transfer & Trust Company, LLC at its principal office in New York, New York 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 2022 annual meeting of shareholders. Furthermore, additional financial information relating to the Corporation is provided in the Corporation's audited consolidated financial statements and MD&A. Shareholders who wish to receive printed copies of these documents free of charge should contact the Corporation's Investor Relations Department using the contact information on the back cover of this Annual Information Form.

APPENDIX A

Appendix A – Contingent Resources Information

NOTE TO READER REGARDING DISCLOSURE OF CONTINGENT RESOURCES INFORMATION

All of the Corporation's contingent resources have been evaluated in accordance with NI 51-101. NSAI has evaluated the Corporation's contingent resources attributable to its Marcellus properties located in Pennsylvania, United States, using the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2022. McDaniel has evaluated the Corporation's contingent resources associated with properties located in North Dakota, United States, using the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2022.

The following sections and tables summarize, as at December 31, 2021, 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 spending, and are presented before deducting income taxes. For additional information, see "*Business of the Corporation – Tax Horizon*", "*Industry Conditions*" and "*Risk Factors*" in the Annual Information Form.

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

The estimated future net revenue to be derived from the production of the contingent resources set out in this Appendix A is based on the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2022, and was utilized by NSAI and McDaniel in their 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 and its Marcellus shale gas property located in Pennsylvania.

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

"**contingent resources**" are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are economically recoverable based on the average of the price forecasts of GLJ, McDaniel and Sproule as of January 1, 2022.

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, 2021, 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, 2021

PROJECT MATURITY SUB-CLASS	CONTINGENT RESOURCES Light & Medium Oil		Heavy Oil		Tight Oil		Natural Gas Liquids		Conventional Natural Gas		Shale Gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)
Development Pending	-	-	-	-	112,561	90,058	14,679	11,750	-	-	721,869	584,044	247,552	199,149

Risked Net Present Value of Future Net Revenue
Contingent Resources (Forecast Prices and Costs)
As of December 31, 2021

RISKED NET PRESENT VALUE OF FUTURE NET REVENUE DISCOUNTED AT (%/Year)

PROJECT MATURITY SUB-CLASS	Before Deducting Income Taxes 0%	5%	10%	15%	20%
			(in US$ millions)		
Development Pending	3,904.5	1,837.1	936.0	507.4	288.2

DESCRIPTION OF PROPERTIES

Outlined below is a description of the Corporation's "best estimate" of economic contingent resources for its 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".

U.S. Crude Oil Properties

An evaluation of the Corporation's interests in the Bakken and Three Forks formations in the Corporation's North Dakota properties was conducted independently by McDaniel, which has attributed an unrisked "best estimate" of 159.1 MMBOE (140.7 MMBOE risked) of economic contingent resources to these formations, effective as of December 31, 2021, an increase of 120% from the estimate as of December 31, 2020. The increase compared to 2020 was the result of 32.2 MMBOE of unrisked contingent resources being converted to undeveloped reserves, which were offset by an additional 119.4 MMBOE of unrisked contingent resources associated with the Bruin Acquisition and the Dunn County Acquisition. 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 283.6 net future drilling locations over and above 316.3 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$2,076.4 million between 2028 and 2036. 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 561.1 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 88% (80% for 1 mile lateral length horizontal wells and 90% for 2 mile lateral length horizontal wells) as their development is expected to immediately follow the reserves development. After application of the chance of development, the risked NPV discounted at 10% is US$795.4 million. The Corporation has approximately 707.6 net reserves wells currently on production in this area.

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

U.S. Natural Gas Properties

NSAI has conducted an independent assessment of the contingent resources attributable to the Corporation's interests in the Marcellus property and has provided an unrisked "best estimate" of economic shale gas contingent resources of approximately 801.4 Bcf (641.2 Bcf risked) at December 31, 2021. The unrisked NPV (discounted at 10%) associated with these contingent resources is US$175.9 million (US$140.7 million risked). Approximately 116.1 Bcf of unrisked contingent resources were reclassified as reserves in 2021. An additional 296.4 Bcf of unrisked contingent resources (237.1 Bcf risked) was assigned in 2021 and attributed to additional economic locations being identified as a result of improved forecast natural gas prices compared to 2020. The remaining contingent resources are economic based on the forecast price and cost assumptions used for the Corporation's year-end 2021 reserves evaluations. This estimate represents a non-reserve land utilization rate of 95% and average well ultimate recovery of approximately 14.4 Bcf. These contingent resources are classified into "development pending" project maturity sub-class as it is anticipated their development will be a continuation of the current reserves development. These contingent resources have an estimated 80% chance of development. It is also estimated that US$525.7 million of capital will be required to develop these contingent resources with multifractured horizontal wells, and development will occur from 2026 to 2045.

The primary contingencies which currently prevent the classification of the Corporation's disclosed contingent resources associated with its Marcellus interests as reserves consist of limitations to development based on adverse topography or other surface restrictions, the receipt of all required regulatory permits and approvals to develop the land, and limited access to confidential information of operators' long-term development plans that would support the recognition of reserves on the Corporation's areas of interest. Significant negative factors related to the estimate include the following: the pace of development, including drilling and infrastructure, is slower than the forecast, risk of adverse regulatory and tax changes, and other issues related to gas development in populated areas. There are a number of inherent risks and contingencies associated with the development of the Corporation's interests in the Marcellus property including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, funding and provision of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in the Annual Information Form.

Appendix B - Supplemental Information About Crude Oil and Natural Gas Producing Activities (unaudited)

The following disclosures, including proved reserves, future net cash flows, and costs incurred attributable to the Corporation's crude oil and natural gas operations have been prepared in accordance with the provisions of the Financial Accounting Standards Board's ASC Topic 932 Extractive Activities – Oil and Gas, which generally utilize definitions and estimations of proved reserves that are consistent with Rule 4-10 of Regulation S-X promulgated by the SEC, but does not necessarily include all of the disclosure required by the SEC disclosure standards set forth in Subpart 1200 of Regulation S-K.

A. ESTIMATED PROVED CRUDE OIL AND NATURAL GAS RESERVE QUANTITIES

Users of this information should be aware that the process of estimating quantities of "proved" crude oil, natural gas and natural gas liquids reserves is very complex, requiring significant subjective decisions in the evaluation of 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.

The U.S. Rules require 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 (the "**Constant Price**"). Proved reserves and production volumes are presented net of royalties in accordance with U.S. practice.

The reserves data disclosed are effective December 31, 2021. Concurrent to the evaluation of the Corporation's Canadian NI 51-101 Standards reserves, McDaniel and NSAI prepared and reviewed estimates of the Corporation's reserves under the U.S. Rules.

Proved reserves, proved developed reserves and proved undeveloped reserves are defined under the U.S. Rules. Proved crude oil and natural gas reserves are those quantities of crude oil and natural 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 reserves data presented in this Appendix B are a summary of evaluations, and as a result the tables may contain slightly different quantities than the evaluations themselves due to rounding. The Corporation also presents reserves estimates in accordance with National Instrument 51-101 "Standard of Disclosure for Oil and Gas Activities" which can differ significantly to those prepared under the U.S. Rules. Additionally, the columns and rows in the tables may not add due to rounding. See "*Presentation of Oil and Gas Reserves, Contingent Resources, and Production Information – Notice to U.S. Readers"* in this Annual Information Form.

Subsequent to December 31, 2021, 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' proved crude oil, natural gas and NGLs reserves are located in the United States, primarily in the states of Colorado, North Dakota and Pennsylvania, as well as western Canada, primarily in Alberta and Saskatchewan. The Corporation's net proved reserves summarized in the following table represent the Corporation's lessor royalty, overriding royalty, and working interest share of reserves, after deduction of any Crown, freehold and overriding royalties as of December 31, 2021.

	United States		Canada		Total		Total
	Crude Oil and NGLs (Mbbls)	Natural Gas (MMcf)	Crude Oil and NGLs (Mbbls)	Natural Gas (MMcf)	Crude Oil and NGLs (Mbbls)	Natural Gas (MMcf)	All Products (Mboe)
Reserves at December 31, 2018	**91,496**	**658,270**	**26,130**	**25,343**	**117,626**	**683,613**	**231,562**
Purchases of reserves in place	-	-	-	-	-	-	-
Sales of reserves in place	-	-	(814)	(190)	(814)	(190)	(845)
Discoveries and extensions	22,689	191,506	375	936	23,064	192,442	55,138
Revisions of previous estimates	(8,193)	(55,505)	695	(450)	(7,498)	(55,956)	(16,823)
Improved recovery	-	-	-	-	-	-	-
Production	(13,216)	(74,455)	(2,707)	(7,882)	(15,923)	(82,337)	(29,646)
Proved Developed and Undeveloped Reserves at December 31, 2019	**92,777**	**719,816**	**23,680**	**17,756**	**116,456**	**737,572**	**239,385**
Purchases of reserves in place	-	-	-	-	-	-	-
Sales of reserves in place	-	-	-	-	-	-	-
Discoveries and extensions	1,931	16,613	-	-	1,931	16,613	4,700
Revisions of previous estimates	(39,543)	(263,700)	(5,115)	943	(44,658)	(262,757)	(88,451)
Improved recovery	-	-	-	-	-	-	-
Production	(12,690)	(65,672)	(2,382)	(4,239)	(15,072)	(69,911)	(26,724)
Proved Developed and Undeveloped Reserves at December 31, 2020	**42,475**	**407,056**	**16,182**	**14,461**	**58,657**	**421,517**	**128,910**
Purchases of reserves in place	60,468	59,185	-	-	60,468	59,185	70,332
Sales of reserves in place	(3,419)	(7,838)	(118)	(1,514)	(3,537)	(9,352)	(5,095)
Discoveries and extensions	75,587	336,511	1,316	503	76,903	337,014	133,072
Revisions of previous estimates	14,984	153,647	4,024	4,960	19,009	158,607	45,443
Improved recovery	-	-	-	-	-	-	-
Production	(18,426)	(75,644)	(2,138)	(2,942)	(20,564)	(78,586)	(33,662)
Proved Developed and Undeveloped Reserves at December 31, 2021	**171,669**	**872,917**	**19,267**	**15,468**	**190,936**	**888,385**	**339,000**
Proved Developed Reserves							
December 31, 2018	50,645	458,649	23,065	25,271	73,710	483,920	154,363
December 31, 2019	49,852	475,155	20,480	17,684	70,332	492,839	152,472
December 31, 2020	37,966	360,446	15,421	14,447	53,387	374,893	115,869
December 31, 2021	89,337	560,221	17,417	15,418	106,754	575,639	202,694
Proved Undeveloped Reserves							
December 31, 2018	40,852	199,621	3,065	72	43,916	199,693	77,198
December 31, 2019	42,925	244,661	3,200	73	46,124	244,733	86,913
December 31, 2020	4,508	46,610	761	13	5,270	46,624	13,040
December 31, 2021	82,332	312,696	1,850	50	84,182	312,746	136,306

Purchases of reserves in place

In 2019, the Corporation acquired no additional working interest reserve volumes through purchases.

In 2020, the Corporation acquired no additional working interest reserve volumes through purchases.

In 2021, the Corporation purchased 60,468 Mbbls of net proved crude oil and NGLs reserves and 59,185 MMcf of natural gas reserves through the acquisition of the Bruin and Hess assets within the Bakken/Three Forks formations in North Dakota.

Sales of reserves in place

In 2019, the Corporation sold working interests in developed and undeveloped land in three crude oil properties located in Saskatchewan and 11 natural gas properties located in Alberta.

In 2020, the Corporation did not sell working interests of any of its reserves in place.

In 2021, the Corporation divested 3,419 Mbbls of net proved crude oil and NGLs reserves and 7,838 MMcf of natural gas reserves from the sale of its crude oil property in the Sleeping Giant area in Montana.
In 2021, the Corporation also sold working interests in developed and undeveloped land in one crude oil property and six natural gas properties located in Alberta, accounting for 118 Mbbls of net proved crude oil and NGLs reserves and 1,514 MMcf of natural gas reserves.

Discoveries and extensions

The Corporation added 22,026 Mbbls, 1,655 Mbbls and 73,683 Mbbls of net proved crude oil and NGLs reserves on its Bakken/Three Forks properties in 2019, 2020 and 2021, respectively. The Company added 179,834 MMcf, 15,299 MMcf and 271,393 MMcf of net proved natural gas reserves in 2019, 2020 and 2021, respectively, on its Marcellus natural gas property. These discoveries and extensions were primarily related to booking locations that, due to the significant improvement in the crude oil and natural gas Constant Price compared to 2020, are now economic, as well as successful well development.

In 2019, Canadian discoveries and extensions accounted for an increase of 282 Mbbls of net proved crude oil reserves in the Saskatchewan Freda Lake crude oil property, and 59 Mbbls of net proved crude oil reserves and 936 MMcf of net proved natural gas reserves in the Ferrier, Fir and Willesden Green North properties located in Alberta.

In 2020, there were no discoveries or extensions in Canadian crude oil or natural gas properties.

In 2021, Canadian discoveries and extensions accounted for an increase of 1,293 Mbbls of net proved crude oil reserves and 50 MMcf of natural gas reserves in the Giltedge and Medicine Hat Glauconitic C crude oil properties, and 23 Mbbls of net proved crude oil and NGLs reserves and 453 MMcf of net proved natural gas reserves in the Ferrier property, all located in Alberta.

Revisions of previous estimates

In 2019, negative revisions to United States crude oil reserves were primarily due to a decrease in the crude oil Constant Price, as well as economic truncation due to an increase in operating expenses. Negative revisions to United States natural gas were primarily due to revised development plans and deletion of proved undeveloped wells in the Marcellus natural gas property.

In 2020, negative revisions to United States crude oil reserves were primarily due to a decrease in the crude oil Constant Price, which caused economic truncation of producing volumes and the removal of undeveloped locations that were no longer economic. Negative revisions to United States natural gas reserves were also primarily due to a decrease in the natural gas Constant Price, which caused economic truncations of producing volumes and the removal of no longer economic undeveloped locations.

In 2021, positive revisions to United States crude oil reserves were primarily due to an increase in the crude oil Constant Price compared to 2020. Positive revisions to United States natural gas reserves were also primarily due to an increase in the natural gas Constant Price compared to 2020.

In 2019, positive revisions to Canadian crude oil reserves were primarily due to improved production performance. Negative revisions to Canadian natural gas reserves were primarily due to a decrease in the natural gas Constant Price compared to 2018.

In 2020, negative revisions to Canadian crude oil reserves were due to negative revisions to previous estimates in the Medicine Hat Glauconitic C polymer flood and a decrease in the crude oil Constant Price compared to 2019. Conversely, an increase in the Constant Price for Canadian natural gas compared to 2019 resulted in positive revisions to Canadian natural gas reserves.

In 2021, the positive revisions to Canadian crude oil reserves were primarily due to an increase in the crude oil Constant Price compared to 2020. Positive revisions to Canadian natural gas reserves were also primarily due to an increase in the natural gas Constant Price compared to 2020.

Improved Recovery

There were no improved recovery revisions for the years 2019, 2020 and 2021.

B. CAPITALIZED COSTS RELATED TO CRUDE OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation and depletion, including impairments, relating to the Corporation's crude oil and natural gas exploration, development and producing activities are as follows:

	For the Year Ended December 31,		
	2021	2020	2019
	(in US$ thousands)		
Capitalized costs(1)	$ 13,075,987	$ 11,966,258	$ 11,615,646
Less accumulated depletion, depreciation and impairment	(11,822,482)	(11,513,956)	(10,424,451)
Net capitalized costs	$ 1,253,505	$ 452,302	$ 1,191,195

Note:
(1) Includes capitalized costs of proved and unproved properties.

C. COSTS INCURRED IN CRUDE OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred in connection with crude oil and natural gas acquisition, exploration and development activities are presented in the table below. Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire crude oil and natural 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 crude oil and natural 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, 2021		
	United States	Canada	Total
	(in US$ thousands)		
Acquisition of properties:			
Proved	$ 832,808	2,339	835,147
Unproved	-	-	-
Exploration costs	861	73	934
Development costs	331,341	25,528	356,869
	$ 1,165,010	$ 27,940	$ 1,192,950

	For the Year Ended December 31, 2020		
	United States	Canada	Total
	(in US$ thousands)		
Acquisition of properties:			
Proved	$ —	$ 225	$ 225
Unproved	5,522	1,744	7,266
Exploration costs	480	98	578
Development costs	200,986	18,136	219,122
	$ 206,988	$ 20,203	$ 227,191

	For the Year Ended December 31, 2019		
	United States	Canada	Total
	(in US$ thousands)		
Acquisition of properties:			
Proved	$ 926	$ 2,085	$ 3,011
Unproved	12,946	2,452	15,398
Exploration costs	463	271	734
Development costs	442,546	42,899	485,445
	$ 456,881	$ 47,707	$ 504,588

D. RESULTS OF OPERATIONS FOR CRUDE OIL AND GAS PRODUCING ACTIVITIES

The following table sets forth revenue and direct cost information relating to the Corporation's crude oil and natural gas producing activities for the years ended December 31, 2021, 2020 and 2019:

	For the Year Ended December 31, 2021		
	United States	Canada	Total
	(in US$ thousands)		
Revenue			
Sales[1]	$ 1,355,253	127,322	1,482,575
Deduct[2]			
Production costs[3]	472,849	49,846	522,695
Depletion, depreciation and accretion ("DD&A")	246,949	24,387	271,336
Impairment	-	3,420	3,420
Current and deferred income tax provision (recovery)	151,620	(50,176)	101,444
Results of operations for oil and gas producing activities	$ 483,835	$ 99,845	$ 583,680
DD&A per net BOE unit of production	$ 7.96	$ 9.28	$ 8.06

	For the Year Ended December 31, 2020		
	United States	Canada	Total
	(in US$ thousands)		
Revenue			
Sales[1]	$ 480,822	$ 72,917	$ 553,739
Deduct[2]			
Production costs[3]	284,071	49,124	333,195
Depletion, depreciation and accretion ("DD&A")	183,226	34,892	218,118
Impairment	799,997	100,943	900,940
Current and deferred income tax provision (recovery)	(178,551)	(20,425)	(198,976)
Results of operations for oil and gas producing activities	$ (607,921)	$ (91,617)	$ (699,538)
DD&A per net BOE unit of production	$ 7.75	$ 11.30	$ 8.16

	For the Year Ended December 31, 2019		
	United States	Canada	Total
	(in US$ thousands)		
Revenue			
Sales[1]	$ 812,370	$ 133,524	$ 945,894
Deduct[2]			
Production costs[3]	327,207	64,039	391,246
Depletion, depreciation and accretion ("DD&A")	223,874	45,172	269,046
Impairment	-	347,283	347,283
Current and deferred income tax provision (recovery)	38,247	(1,843)	36,404
Results of operations for oil and gas producing activities	$ 223,042	$ (321,127)	$ (98,085)
DD&A per net BOE unit of production	$ 8.74	$ 11.24	$ 9.08

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 crude oil and gas producing activities.

(3) Production costs include operating costs, transportation costs and production taxes.

E. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED CRUDE 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 Corporation's crude oil and natural gas reserves:

	As at December 31, 2021		
	United States	Canada	Total
	(in $US millions)		
Future cash inflows	$ 10,499	1,023	11,522
Future production costs	3,293	425	3,718
Future development and asset retirement costs	1,486	140	1,626
Future income tax expenses	1,064	-	1,064
Future net cash flows	$ 4,655	459	5,114
Deduction: 10% annual discount factor	1,552	149	1,701
Standardized measure of discounted future net cash flows	$ 3,103	309	3,413

	As at December 31, 2020		
	United States	Canada	Total
	(in $US millions)		
Future cash inflows	$ 1,375	427	1,802
Future production costs	832	256	1,088
Future development and asset retirement costs	174	199	373
Future income tax expenses	-	-	-
Future net cash flows	$ 370	(29)	341
Deduction: 10% annual discount factor	41	(69)	(27)
Standardized measure of discounted future net cash flows	$ 329	40	368

	As at December 31, 2019		
	United States	Canada	Total
	(in $US millions)		
Future cash inflows	$ 4,796	962	5,758
Future production costs	1,658	443	2,101
Future development and asset retirement costs	1,023	240	1,264
Future income tax expenses	191	-	191
Future net cash flows	$ 1,924	279	2,203
Deduction: 10% annual discount factor	670	57	726
Standardized measure of discounted future net cash flows	$ 1,255	222	1,476

F. CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED CRUDE OIL AND NATURAL GAS RESERVES

	2021	2020	2019
	(in $US millions)		
Beginning of year	**$** 368	**$** 1,476	$ 1,824
Sales of oil and natural gas produced, net of production costs	(960)	(221)	(555)
Net changes in sales prices and production costs	2,347	(2,030)	(777)
Development costs incurred during the period	302	217	465
Changes in estimated future development costs	(1,278)	557	(344)
Extension, discoveries and improved recovery, net of related costs	2,285	30	667
Purchase of reserves in place	1,214	-	-
Sales of reserves in place	(12)	-	(5)
Net change resulting from revisions in previous quantity estimates	(251)	122	(84)
Accretion of discount	26	136	181
Net change in income taxes	(630)	82	116
Other significant factors (Exchange rate)	3	(2)	(11)
End of year	**$** 3,413	**$** 368	$ 1,476

ADDITIONAL RESERVES INFORMATION CALCULATED IN ACCORDANCE WITH U.S. RULES

G. NET RESERVES PROVED RESERVES SUMMARY

The following table sets forth a summary of the Corporation's total proved reserves based on volumes that are calculated in accordance to U.S. Rules, using net reserves and Constant Prices and Costs, and presented by product types that the Corporations used to report under the Canadian Standards.

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Net								
Proved developed producing	4,656	12,171	72,859	89,686	15,281	15,067	555,906	200,130
Proved developed non-producing	-	-	1,524	1,524	262	-	4,665	2,564
Proved undeveloped	557	1,293	70,314	72,164	12,018	50	312,696	136,306
Total Proved	5,213	13,464	144,697	163,374	27,561	15,117	873,268	339,000

H. NET PROVED RESERVES RECONCILIATION

The following table sets forth a summary of the Corporation's total proved reserves based on volumes that are calculated in accordance to U.S. Rules, using net reserves and Constant Prices and Costs, and presented by product types that the Corporations used to report under the Canadian Standards.

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2020	4,964	10,642	37,740	53,345	5,311	14,052	407,466	421,517	128,910
Purchases of reserves in place	-	-	50,713	50,713	9,755	-	59,185	59,185	70,332
Sales of reserves in place	(10)	-	(3,429)	(3,438)	(98)	(1,419)	(7,933)	(9,352)	(5,095)
Discoveries and extensions	7	1,293	64,546	65,845	11,057	503	336,511	337,014	133,071
Revisions of previous estimates	1,067	2,734	10,816	14,617	4,392	4,835	153,771	158,606	45,443
Improved recovery	-	-	-	-	-	-	-	-	-
Production	(814)	(1,205)	(15,688)	(17,708)	(2,856)	(2,853)	(75,733)	(78,586)	(33,661)
Proved Reserves at Dec. 31, 2021	5,213	13,464	144,697	163,374	27,561	15,117	873,268	888,385	339,000

I. FUTURE DEVELOPMENT COSTS

The following table sets forth a summary of the amount of development costs deducted in the estimation of the net present value of future cash flows associated with the Corporation's proved reserves.

	U.S. Standards[(1)]
Future Development Costs	**Proved Reserves**
(US$ millions)	
2022	332
2023	359
2024	352
2025	312
2026	8
2027	3
Remainder	2
Total FDC Undiscounted	**1,369**
Total FDC Discounted at 10%	**1,152**

Note:
1) FDC under U.S. Standards are not inflated.

Appendix C – 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"):

- We have audited, evaluated and reviewed, as applicable, the Corporation's reserves data and contingent resources data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, estimated using forecast prices and costs.

- 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.

- 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).

- 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.

- 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, 2021, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation or Review Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (in US$ thousands)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	December 31, 2021	Canada	-	US$ 281,756.6	112,663.1	US$ 394,419.6
McDaniel & Associates Consultants Ltd.	December 31, 2021	North Dakota & Colorado, USA	-	US$4,914,390.9	-	US$ 4,914,390.9
Netherland, Sewell & Associates, Inc.	December 31, 2021	Pennsylvania, USA	-	US$ 655,198.9	-	US$ 655,198.9
TOTALS				$ 5,851,346.3	$ 112,663.1	$ 5,964,009.4

- 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 US$ thousands)		
					Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	McDaniel & Associates Consultants Ltd.	December 31, 2021	North Dakota, USA	140.7	US$ -	US$ 795,356.0	$US795,356.0
Development Pending Contingent Resources (2C)	Netherland, Sewell & Associates, Inc.	December 31, 2021	Pennsylvania, USA	106.9	US$ -	$US 140,682.5	US$140,682.5

- 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.

- 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.

- 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.

- Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by B. Hamm"
B. Hamm, P.Eng.
President & CEO

Calgary, Alberta, Canada

February 23, 2022

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 23, 2022

Appendix D – 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:

1. reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators

2. 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

3. 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:

- the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and other oil and gas information

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

- the content and filing of this report

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

ENERPLUS CORPORATION

"*Ian C. Dundas*"
Ian C. Dundas

President & Chief Executive Officer

"*John E. Hoffman*"
John E. Hoffman
Vice President, Digital Technology & Corporate Sustainability

"*Hilary Foulkes*"
Hilary Foulkes
Director

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

February 23, 2022

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

A. THE AUDIT & RISK MANAGEMENT COMMITTEE'S CHARTER

The charter of the Audit & Risk Management Committee (the "**Committee**") of the board of directors of the Corporation is included in this Appendix E.

B. COMPOSITION OF THE AUDIT & RISK MANAGEMENT COMMITTEE

The current members of the Committee are Jeffrey W. Sheets (Committee Chair), Judith D. Buie and Sheldon B. Steeves. Each member of the Committee is independent and financially literate within the meaning of National Instrument 52-110 and the NYSE listing standards.

C. RELEVANT EDUCATION AND EXPERIENCE

Name (Director Since)	Principal Occupation and Biography
Jeffrey W. Sheets (B.Sc. (Chemical Engineering), MBA (Finance)) (Director since December 2017) Other Public Directorships • Schlumberger Limited (global oilfield services & equipment) • Westlake Chemical Corporation (chemicals & plastics sales & manufacturing)	Mr. Sheets served as executive vice president and chief financial officer of ConocoPhillips Company from October 2010 to February 2016. Mr. Sheets was associated with ConocoPhillips and its predecessor companies for more than 36 years and served in a variety of roles, including senior vice president of planning and strategy as well as vice president and treasurer. He began his career in 1980 as a process engineer with Phillips Petroleum Company. Mr. Sheets serves on the board of directors of Schlumberger Limited and Westlake Chemical Corporation and is a former director of DCP Midstream Partners LP. Mr. Sheets received a Bachelor's degree in Chemical Engineering from the Missouri University of Science and Technology and an MBA from the University of Houston. Mr. Sheets is a member of the Board of Trustees at the Missouri University of Science and Technology.
Judith D. Buie (B.Sc. (Chemical Engineering)) (Director since January 2020)	Ms. Buie has spent over 30 years in the upstream oil and gas business leading business development initiatives and managing oil and gas assets through different commodity and life cycles. From 2012 to 2017, Ms. Buie was Co-President and Senior Vice President Engineering for RPM Energy Management LLC, a private company which worked exclusively with KKR, a leading global investment firm, to evaluate and manage oil and gas investments. Prior to RPM, Ms. Buie held a variety of leadership and technical positions with Newfield Exploration Company from 2001 to 2011, and prior thereto she served in various technical roles at BP, Vastar Resources and ARCO. Ms. Buie currently serves on the board of directors of a private oil and gas company. She also serves as an oil and gas industry advisor. Ms. Buie received a Bachelor of Science in Chemical Engineering from Texas A&M University.

Name (Director Since)	Principal Occupation and Biography
Sheldon B. Steeves (B. Sc. (Geology)) (Director since June 2012) Other Public Directorships • NuVista Energy Ltd. (oil & gas company) • PrairieSky Royalty Ltd. (oil & gas royalty company)	Mr. Steeves has over 40 years of experience in the North American oil and gas industry and is currently a corporate director. From January 2001 until April 2012, Mr. Steeves was Chairman and Chief Executive Officer of Echoex Ltd., a junior private oil and gas 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. He 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 KPMG in 2021 and 2020 were pre-approved by the Committee. Based on the Committee's discussions with management and the independent auditors, the Committee is of the view that the provision of the non-audit services by KPMG described above is compatible with maintaining that firm's independence from the Corporation.

E. EXTERNAL AUDITOR SERVICE FEES

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

(in US$ thousands)	2021	2020
Audit fees(1)	$ 897.6	$ 690.2
Audit-related fees(2)	-	-
Tax fees(3)	190.0	24.2
All other fees(4)	-	-
TOTAL	**$ 1,087.6**	**$ 714.4**

Notes:

1. Audit fees were for professional services rendered 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 and review to identify recovery opportunities.
4. All other fees related to products and services 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, virtually or by telephone of a majority of the Committee's members shall constitute a quorum for any meeting of the Committee. All actions of the Committee will require the vote of a majority of its members present at a meeting of the Committee at which a quorum is present.

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

II. PURPOSE OF THE COMMITTEE

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

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

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

III. COMPOSITION AND COMPETENCY OF THE COMMITTEE

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

IV. MEETINGS OF THE COMMITTEE

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

V. DUTIES AND ACTIVITIES OF THE COMMITTEE

Evaluating and monitoring the performance and independence of external auditors

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

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

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

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

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

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

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

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

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

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

   d) pre-approving the nature of non-audit related services and the fees thereon

   e) conducting private sessions with the external auditors and encouraging direct communications between the Chair of the Committee and the audit partner

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

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

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

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

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

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

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

8. Receipt of certifications from the CEO and CFO

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

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

   b) the qualitative judgments of the external auditors about the appropriateness, not just the acceptability, of accounting principles and financial disclosure practices used or proposed to be adopted by the

Corporation and, particularly, their views about alternate accounting treatments and their effects on the financial results

c) the methods used to account for significant unusual transactions

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

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

f) significant recorded and unrecorded audit adjustments

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

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

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

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

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

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

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

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

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

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

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

15. Receive periodic reports from the external auditors and management to assess the impact of significant accounting or financial reporting developments proposed by the CICA, the AICPA, the Financial Accounting Standards Board, the SEC, the relevant Canadian securities commissions, stock exchanges or other regulatory body, or any other significant accounting or financial reporting related matters that may have a bearing on the Corporation and

16. Review annually the report of the external auditors on the Corporation's internal controls over financial reporting describing any material issues raised by the most recent reviews of internal controls and management information systems or by any inquiry or investigation by governmental or professional authorities and any recommendations made and steps taken to deal with any such issues

Review of Business Risks

17. Review with management the process followed to conduct the Corporation's key risk assessment and review 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.

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