FORM 40-F

Annual reports filed by certain Canadian issuers pursuant to Section 15(d) and Rule 15d-4

Filing Date: **2023-03-02** | Period of Report: **2022-12-31**
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FILER

Crescent Point Energy Corp.

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SIC: **1311** Crude petroleum & natural gas

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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

☒ ANNUAL REPORT PURSUANT TO SECTION 13(A) OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2022 Commission File Number 001-36258

CRESCENT POINT ENERGY CORP.

(Exact name of Registrant as specified in its charter)

Alberta	**1311**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

Suite 2000, 585-8th Avenue S.W.
Calgary, Alberta
T2P 1G1
(403) 693-0020
(Address and telephone number of registrant's principle executive offices)

CT Corporation System
111 - 8th Avenue
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act.

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares	**CPG**	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act.

None

(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None

(Title of Class)

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 the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

550,888,983 Common Shares (as at December 31, 2022).

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.

☐

† 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.

☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

☐

The annual report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the Registrant's Registration Statement under the Securities Act of 1933, as amended: Form F-10 (File No. 333-257761), Form S-8 (File No. 333-226210) and Form F-3D (File No. 333-205592)

EXPLANATORY NOTE

Crescent Point Energy Corp. (the "Registrant" or "we") is a Canadian issuer eligible to file its annual report pursuant to Section 13 of Exchange Act, on Form 40-F pursuant to the multi-jurisdictional disclosure system of the Exchange Act. We are a "foreign private issuer" as defined in Rule 3b-4 under the Exchange Act. Accordingly, our equity securities are exempt from Sections 14(a), 14(b), 14(c), 14(f) and 16 of the Exchange Act pursuant to Rule 3a12-3.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 40-F and the exhibits attached hereto contain or incorporate by reference "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Please see "Special Notes to Reader" in the Annual Information Form of the Registrant for the year ended December 31, 2022, filed as Exhibit 99.1 to this Annual Report on Form 40-F for a discussion of risks, uncertainties, and assumptions that could cause actual results, performance or achievements to differ materially from those expressed in, or implied by, these forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These forward-looking statements are based on the beliefs, expectations and opinions of management on the date the statements are made. We do not assume any obligation to update forward-looking statements, except as required by applicable securities laws, if circumstances or management's beliefs, expectations or opinions should change.

PRINCIPAL DOCUMENTS

The following documents are filed as part of this Annual Report on Form 40-F:

A. Annual Information Form

For the Registrant's Annual Information Form for the fiscal year ended December 31, 2022, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2022, including the report of its Independent Auditor (PCAOB ID 271) with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F.

C. Management's Discussion and Analysis

For the Registrant's Management's Discussion and Analysis of the operating and financial results for the fiscal year ended December 31, 2022, see Exhibit 99.3 of this Annual Report on Form 40-F.

D. Supplementary Information

For the Registrant's Supplementary Information about Extractive Activities - Oil and Gas (unaudited) for the fiscal year ended December 31, 2022, see Exhibit 99.10 of this Annual Report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

A. Certifications

The required disclosure is included in Exhibits 99.4, 99.5, 99.6 and 99.7 of this Annual Report on Form 40-F.

B. Disclosure Controls and Procedures

As of the end of the Registrant's fiscal year ended December 31, 2022, an internal evaluation was conducted under the supervision of and with the participation of the Registrant's management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Registrant's "disclosure controls and procedures" as defined in Rule 13a-15(e) under Securities and Exchange Act of 1934, as amended (the "Exchange Act"). Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of the Registrant's disclosure controls and procedures were effective in ensuring that the information required to be disclosed in the reports that the Registrant files with or submits to the Securities and Exchange Commission (the "Commission") is recorded, processed, summarized and reported, within the required time periods.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

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

The required disclosure is included in the "Management's Report" that accompanies the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2022, filed as Exhibit 99.2 to this Annual Report on Form 40-F.

D. Attestation of Report of Independent Auditor

The attestation report of PricewaterhouseCoopers LLP is included in the Independent Auditor's Report that accompanies the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2022, filed as Exhibit 99.2 of this Annual Report on Form 40-F, and is incorporated herein by reference.

E. Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2022, 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 Registrant's Board of Directors has determined that Mr. M. Jackson, Mr. T. Goldthorpe and Ms. M. Wight are "audit committee financial experts" (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its audit committee and are "independent" (as defined by the New York Stock Exchange corporate governance rules applicable to foreign private issuers).

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 in paragraph 9(b) of General Instruction B to Form 40-F) ("Code of Ethics"), which is applicable to the directors, officers, employees and consultants of the Registrant and its affiliates (including, its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions). The Code of Ethics is available on the Registrant's website at https://crescentpointenergy.com/corporate-responsibility/esg-policies.

In the past fiscal year, the Registrant has not granted any waiver, including an implicit waiver, from any provision of its Code of Ethics.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The required disclosure is included under the heading "External Auditor Services Fees" in the Registrant's Annual Information Form for the year ended December 31, 2022, filed as Exhibit 99.1 to this Annual Report on Form 40-F, and is incorporated herein by reference.

PRE-APPROVAL POLICIES AND PROCEDURES

The information required is included under the heading "*Relationship and External Auditors*" in Appendix A - Audit Committee - Terms of Reference of the Registrant's Annual Information Form for the fiscal year ended December 31, 2022, incorporated by reference as Exhibit 99.1 to this Annual Report on Form 40-F.

HOURS EXPENDED ON AUDIT ATTRIBUTED TO PERSONS OTHER THAN THE PRINCIPAL ACCOUNTANT'S EMPLOYEES

Not Applicable.

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 fiscal year ended December 31, 2022, filed 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 its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, cash requirements or capital resources.

DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The required disclosure is included under the heading "Contractual Obligations and Commitments" in the Registrant's Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2022, filed as Exhibit 99.3 to this Annual Report on Form 40-F.

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 Registrant's Audit Committee members consist of Mr. M. Jackson, Mr. T. Goldthorpe, Mr. F. Langlois and Ms. M. Wight all of whom, in the opinion of the directors, are independent (as determined under Rule 10A-3 of the Exchange Act.)

Please refer to the Company's AIF attached as Exhibit 99.1 to this annual report on Form 40-F for details in connection with each of these members and their qualifications.

The members of the Audit Committee do not have fixed terms and are appointed and replaced from time to time by resolution of the directors.

The Audit Committee meets with the CEO, CFO and the Company's independent auditors to review and inquire into matters affecting financial reporting, the system of internal accounting and financial controls, as well as audit procedures and audit plans. The Audit Committee also recommends to the Board of Directors which independent registered public auditing firm should be appointed by the Company. In addition, the Audit Committee reviews and recommends to the Board of Directors for approval the annual financial statements and the Management's Discussion and Analysis of Financial Condition and Results of Operations, and undertakes other activities required by exchanges on which the Company's securities are listed and by regulatory authorities to which the Company is held responsible.

The full text of the Audit Committee Terms of Reference is disclosed in the Company's AIF, attached hereto as Exhibit 99.1, and is incorporated by reference in this annual report on Form 40-F.

NYSE STATEMENT OF CORPORATE GOVERNANCE DIFFERENCES

As a Canadian corporation listed on the NYSE, we are not required to comply with most of the NYSE's corporate governance standards, and instead may comply with Canadian corporate governance practices. However, we are required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. These significant differences are disclosed on our website at https://crescentpointenergy.com/corporate-responsibility/tsx-supplemental-material. Except as disclosed on our website, we are in compliance with the NYSE corporate governance standards in all significant respects.

MINE SAFETY DISCLOSURE

Pursuant to Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, issuers that are operators, or that have a subsidiary that is an operator, of a coal or other mine in the United States are required to disclose in their periodic reports filed with the SEC information regarding specified health and safety violations, orders and citations, related assessments and legal actions, and mining-related fatalities under the regulation of the Federal Mine Safety and Health Review Administration under the Federal Mine Safety and Health Act of 1977. During the fiscal year ended December 31, 2022, we were not subject to any of the specified violations, orders, citations or other legal actions under the Federal Mine Safety and Health Act of 1977.

DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

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 in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

DISCLOSURE PURSUANT TO SECTION 13(r) OF THE EXCHANGE ACT

In accordance with Section 13(r) of the Exchange Act, the Registrant is required to include certain disclosures in its periodic reports if it or any of its affiliates knowingly engaged in certain specified activities during the period covered by the report. Neither the Registrant nor is affiliates have knowingly engaged in any transaction or dealing reportable under Section 13(r) of the Exchange Act during the year ended December 31, 2022.

CONSENT TO SERVICE OF PROCESS

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

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 report to be signed on its behalf by the undersigned, thereto duly authorized.

Date: March 2, 2023	**Crescent Point Energy Corp.**	
	By:	/s/ Ken Lamont
	Name:	Ken Lamont
	Title:	Chief Financial Officer

Form 40-F Table of Contents

Exhibit No.	Document
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2022.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2022 together with the Report of Independent Registered Public Accounting Firm thereon.
99.3	Management's Discussion and Analysis of the operating and financial results of the Registrant for the year ended December 31, 2022.
99.4	Certification of Chief Executive Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.5	Certification of Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.6	Certification of Chief Executive Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.7	Certification of Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.8	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm
99.9	Consent of McDaniel & Associates Consultants Ltd., Independent Engineers
99.10	Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
101	Interactive Data File
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

Exhibit 99.1

CRESCENT POINT ENERGY CORP.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2022

Dated March 1, 2023

Contents

SPECIAL NOTES TO READER

Any "financial outlook" or "future oriented financial information" in this annual information form, as defined by applicable securities legislation, has been approved by management of Crescent Point (as defined herein). Such financial outlook or future oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

This AIF (as defined herein) and other reports and filings made with the securities regulatory authorities include certain statements that constitute "forward-looking statements" within the meaning of section 27A of the Securities Act of 1933, section 21E of the Securities Exchange Act of 1934 and the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" for the purposes of Canadian securities regulation (collectively, "forward-looking statements"). All forward-looking statements are based on our beliefs and assumptions based on information available at the time the assumption was made. Crescent Point has tried to identify such forward-looking statements by use of such words as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", "intend", "projected", "sustain", "continues", "strategy", "potential", "projects", "grow", "take advantage", "estimate", "well-positioned" and similar expressions, but these words are not the exclusive means of identifying such statements. These forward-looking statements 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 statements. Crescent Point believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements speak only as of the date of this AIF or, if applicable, as of the date specified in this AIF.

In particular, this AIF contains forward-looking statements pertaining, among other things, to the following:

- corporate strategy and anticipated financial and operational performance;
- forecast prices and the expected impact of commodity price fluctuations on cash available to pay dividends and return capital to shareholders;
- return of capital framework that targets the return of up to 50% of the Corporation's discretionary excess cash flow;
- hedging strategy, including expected outcomes, and the approach to managing physical delivery contracts;
- risk mitigation strategy and the expected outcomes;
- the potential impact of competition and our working relationships with industry partners and joint operators on Crescent Point's business;
- business prospects;
- the performance characteristics of Crescent Point's oil and natural gas properties, including but not limited to oil and natural gas production levels;
- anticipated future cash flows and oil and natural gas production levels;
- projected returns and exploration potential of our assets;
- the potential of Crescent Point's plays;
- future development plans, including focus areas;
- forecast costs and expenses associated with Crescent Point's business, including capital expenditure programs and how they will be funded;
- leverage objectives;
- corporate and asset acquisitions and dispositions;
- drilling programs;
- expected location inventory development timing;

- expected production breakdown by area on a Proved and Proved plus Probable production basis;
- the quantity of oil and natural gas reserves;
- projections of commodity prices and costs;
- future enhanced oil recovery and waterflood programs;
- the possible impacts of curtailment on Crescent Point;

- the impacts of the Redwater decision and other legal decisions;
- expected decommissioning, abandonment, remediation and reclamation costs;
- Crescent Point's tax horizon;
- the impact of the Canada-United States-Mexico Agreement;
- expected trends in environmental regulation, including the anticipated impact the trends may have on operations and compliance costs;
- the impact, and projected long-term impacts, of the pricing of carbon and greenhouse gases;
- payment of dividends, including special dividends, and the repurchase of Common Shares (as defined herein) by Crescent Point, including pursuant to its normal course issuer bid;
- supply and demand for oil and natural gas;
- the actions of OPEC+;
- expectations of legal and regulatory changes and implementations and change in governmental and regulatory bodies;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes, including royalty regimes applicable to natural resources;
- stock option grants;
- the impacts of the war in Ukraine;
- the impacts of COVID-19; and
- risks related to the regulatory, social and market efforts to address climate change.

By their nature, such forward-looking statements are subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements, including those material risks discussed in our Management's Discussion and Analysis for the year ended December 31, 2022, under the headings "Risk Factors" and "Forward-Looking Information" and as disclosed in this AIF. The material assumptions and factors in making forward-looking statements are disclosed in the Management's Discussion and Analysis for the year ended December 31, 2022, under the headings "Overview", "Development Capital Expenditures", "Commodity Derivatives", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Guidance".

This information contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Crescent Point's control. Such risks and uncertainties include, but are not limited to: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations, pipeline restrictions and blowouts; the impacts of the war in Ukraine; the actions of OPEC+; the risk of carrying out operations with minimal environmental impact; industry conditions, including changes in laws and regulations, the adoption of new environmental laws and regulations, and changes in how environmental laws and regulations are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs and of dispositions and monetization; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; the impacts of COVID-19; fluctuations in foreign exchange and interest rates; stock market volatility; failure to realize the anticipated benefits of acquisitions and dispositions; general economic, market and business conditions; inflation; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; tax laws and changes thereto, crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the control of Crescent Point, including those listed under "Risk Factors" in this AIF. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as each of these are interdependent and Crescent Point's future course of action depends on management's assessment of all information available at the relevant time.

Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserve values may be greater than or less than the estimates provided herein.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable crude oil, natural gas and natural gas liquids reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable crude oil, natural gas liquids and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Crescent Point's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. In addition, the discounted and undiscounted net present value of future net revenues attributable to reserves do not represent fair market value; and the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Crescent Point's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits, if any, Crescent Point will derive therefrom.

Barrels of oil equivalent ("**boe**") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Netback received is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback received excludes realized commodity derivative gains and losses. Netback received is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. Netback received is equivalent to "operating netback" referenced in the MD&A. The calculation of netback received is shown in the Production History section of this AIF.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for the year.

Additional information on these and other factors that could affect Crescent Point's operations or financial results are included in Crescent Point's reports on file with Canadian and U.S. securities regulatory authorities (including our Annual Report on Form 40-F and Management's Discussion and Analysis). Readers are cautioned not to place undue reliance on the forward-looking information, which is given as of the date it is expressed in this AIF or otherwise. We do not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required pursuant to applicable law. All subsequent forward-looking statements, whether written or oral, attributable to Crescent Point or persons acting on the Corporation's behalf are expressly qualified in their entirety by these cautionary statements.

Currency Presentation

All references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated. The daily rate of exchange on December 31, 2022, as reported by the Bank of Canada for the conversion of Canadian dollars into United States dollars was Cdn.$1.00 equals U.S.$0.7383 and for the conversion of United States dollars into Canadian dollars was U.S.$1.00 equals Cdn.$1.3544. The following table sets forth, for 2022 and 2021, the high, low and average of the daily exchange rates for that year, each for one U.S. dollar expressed in Canadian dollars as reported by the Bank of Canada.

	Year ended December 31, 2022 (Cdn$/Usd)	Year ended December 31, 2021 (Cdn$/Usd)
High	0.8031	0.8306
Low	0.7217	0.7727
Average	0.7692	0.7980

Presentation of our Reserve and Resource Information

Current SEC reporting requirements permit oil and gas companies to disclose Probable reserves (as defined herein), in addition to the required disclosure of Proved reserves. Under current SEC requirements, net quantities of reserves are required to be disclosed, which requires disclosure on an after-royalties basis and does not include reserves relating to the interests of others. For a description of these and additional differences between Canadian and U.S. standards of reporting reserves, see "*Risk Factors — Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States*".

New York Stock Exchange

As a Canadian corporation listed on the NYSE (as defined herein), we are not required to comply with most of the NYSE's corporate governance standards and, instead, may comply with Canadian corporate governance practices. We are, however, required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on our website at www.crescentpointenergy.com, we are in compliance with the NYSE corporate governance standards.

GLOSSARY

In this AIF, the capitalized terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**AER**" means the Alberta Energy Regulator.

"**Alberta EPA**" means the Alberta Ministry of Environment and Protected Areas.

"**AIF**" means this annual information form of the Corporation dated March 1, 2023 for the year ended December 31, 2022.

"**Board**" or "**Board of Directors**" means the board of directors of the Corporation.

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

"**Conversion Arrangement**" means the plan of arrangement under Section 193 of the ABCA, completed on July 2, 2009 pursuant to which the Trust effectively converted from an income trust to a corporate structure.

"**CPEUS**" means Crescent Point Energy U.S. Corp.

"**CPHL**" means Crescent Point Holdings Ltd.

"**CPUSH**" means Crescent Point U.S. Holdings Corp.

"**Crescent Point**" or the "**Corporation**" means Crescent Point Energy Corp., formerly Wild River Resources Ltd., a corporation amalgamated under the ABCA and, where applicable, includes its subsidiaries and affiliates.

"**DRIP**" means the Premium Dividend™ and Dividend Reinvestment Plan of the Corporation.

"**DSU Plan**" means the Deferred Share Unit Plan of the Corporation.

"**ESVP**" means the Employee Share Value Plan of the Corporation.

"**FAST Act**" means the *Fixing America's Surface Transportation Act*.

"**Greenhouse Gases**" or "**GHGs**" means any or all of, including but not limited to, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6).

"**IFRS**" means International Financial Reporting Standards as adopted by the Canadian Accounting Standards Board for periods beginning on and after January 1, 2011.

"**McDaniel**" means McDaniel & Associates Consultants Ltd.

"**MD&A**" means the management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2022.

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

"**NI 51-101**" means "*National Instrument 51-101 – Standards for Disclosure for Oil and Gas Activities*".

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

"**OPEC+**" means the Organization of the Petroleum Exporting Countries and cooperating oil-exporting nations.

"**Partnership**" means Crescent Point Resources Partnership, a general partnership formed under the laws of the Province of Alberta, having CPHL and the Corporation as partners.

"**PSU Plan**" means the Performance Share Unit Plan of the Corporation.

"**Restricted Share Bonus Plan**" means the Restricted Share Bonus Plan of the Corporation.

"**SDP**" means the Share Dividend Plan of the Corporation.

"**SEC**" means the U.S. Securities and Exchange Commission.

"**Shareholders**" means the holders from time to time of Common Shares.

"**Stock Option Plan**" means the Stock Option Plan of the Corporation.

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

"**Trust**" means Crescent Point Energy Trust, an unincorporated open ended investment trust governed by the laws of the Province of Alberta that was dissolved pursuant to the Conversion Arrangement.

"**Trust Units**" means the trust units of the Trust.

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

"**U.S.**" means the United States of America.

"**Unitholders**" means holders of Trust Units.

For additional definitions used in this AIF, please see "Statement of Reserves Data and Other Oil and Gas Information - Notes and Definitions".

SELECTED ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
bbls	barrels	Mcf/d	thousand cubic feet per day
bbls/d	barrels per day		
Mbbls	thousand barrels	Mcfe	thousand cubic feet of gas equivalent converting one barrel of oil to 6 Mcf of natural gas equivalent
NGLs	natural gas liquids		
		MMcf	million cubic feet
		MMcf/d	million cubic feet per day
		MMBTU	million British Thermal Units

Other	
AECO	the natural gas storage facility located at Suffield, Alberta
boe or BOE	barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
boe/d	barrel of oil equivalent per day
m^3	cubic metres
M$	thousand dollars
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
MM$	million dollars
NYMEX	New York Mercantile Exchange natural gas price
tCO2e/boe	tonnes of carbon dioxide equivalent per barrel of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CURRENCY OF INFORMATION

The information set out in this AIF is stated as at December 31, 2022, unless otherwise indicated. Capitalized terms used but not defined in the text are defined in the Glossary.

OUR ORGANIZATIONAL STRUCTURE

The Corporation

Crescent Point Energy Corp. ("**Crescent Point**" or the "**Corporation**" and, together with its direct and indirect subsidiaries and partnerships, where appropriate, "**we**", "**our**" or "**us**") is the successor to the Trust, following the completion of the "conversion" of the Trust from an income trust to a corporate structure under the Conversion Arrangement. Pursuant to the Conversion Arrangement, Unitholders of the Trust exchanged their Trust Units for Common Shares of the Corporation on a one-for-one basis.

The Corporation was originally incorporated pursuant to the provisions of the *Company Act* (British Columbia) on April 20, 1994 as 471253 British Columbia Ltd. 471253 British Columbia Ltd. changed its name to Westport Research Inc. ("**Westport**") on August 12, 1994. On August 1, 2006, Westport was continued into Alberta under the ABCA. On October 11, 2006, Westport changed its name to 1259126 Alberta Ltd. ("**1259126**"). On February 8, 2007, 1259126 amended its articles to change its name to Wild River Resources Ltd. ("**Wild River**"), to add a class of non-voting common shares, to change the number of authorized Common Shares from 1,000,000 to unlimited and to change the rights, privileges, restrictions and conditions attaching to such shares, to reorganize its share structure, to change the number of Wild River's issued and outstanding shares on a pro rata basis to an aggregate of 5,000,000 Common Shares, to remove the restrictions on share transfer and to amend the "other provisions" section of the articles. On June 29, 2009, Wild River amended its articles to cancel the non-voting common shares and to change the rights, privileges, restrictions and conditions of the Common Shares to remove the references to the non-voting common shares. On July 2, 2009, in connection with the Conversion Arrangement, Wild River filed Articles of Amendment to give effect to the consolidation of the Common Shares on the basis of 0.1512 of a post-consolidation Common Share for each pre-consolidation Common Share and subsequent Articles of Amendment to change its name to Crescent Point Energy Corp. On January 1, 2011, the Corporation amalgamated with Ryland Oil ULC, Darian Resources Ltd. and Shelter Bay Energy ULC.

The head and principal office of the Corporation is located at Suite 2000, 585 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and its registered office is located at Suite 3700, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

The Corporation is a conventional oil and gas producer with assets strategically focused in properties comprised of high quality, long life, operated, light and medium crude oil, natural gas liquids and natural gas reserves in Western Canada and the United States. We make regular cash dividends to Shareholders from our net cash flow.

Partnership

The Partnership is a general partnership governed by the laws of the Province of Alberta. As set forth in the diagram below under "*Organizational Structure of the Corporation*", the partners of the Partnership are CPHL and the Corporation.

The existing business of the Corporation is carried on through the Partnership and through CPEUS. The Partnership holds all of the Corporation's Canadian operating assets and CPEUS holds all of the Corporation's U.S. operating assets.

CPHL

CPHL is a wholly-owned subsidiary of the Corporation. CPHL is a partner of the Partnership.

CPUSH

Crescent Point U.S. Holdings Corp. is a wholly-owned direct subsidiary of the Corporation.

CPEUS

Crescent Point Energy U.S. Corp. is a wholly-owned indirect subsidiary of the Corporation. CPEUS holds the Corporation's operating assets in the United States.

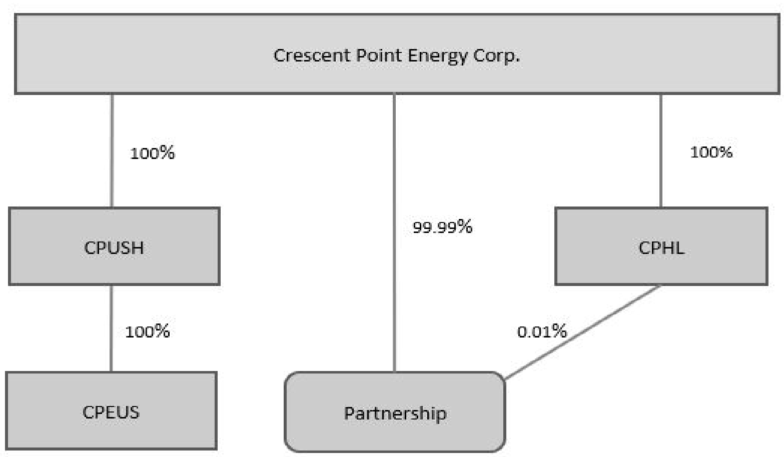
Relationships

The following table provides the name, the percentage of voting securities owned by the Corporation and the jurisdiction of incorporation, continuance or formation of the Corporation's material subsidiaries as at the date hereof.

	Percentage of Voting Securities (Directly or Indirectly)	Jurisdiction of Incorporation/Formation
CPHL	100%	Alberta
Partnership	100%	Alberta
CPUSH	100%	Nevada
CPEUS	100%	Delaware

Organizational Structure of the Corporation

The following diagram describes the inter-corporate relationships among the Corporation and its material direct and indirect subsidiaries described above as at December 31, 2022 and current to March 1, 2023. Reference should be made to the appropriate sections of this AIF for a complete description of the structure of the Corporation.



GENERAL DEVELOPMENT OF THE BUSINESS OF THE CORPORATION

History

The following is a description of the general development of the business of Crescent Point over the past three years.

2020

On January 20, 2020, Crescent Point sold certain associated gas infrastructure assets in Saskatchewan to Steel Reef Infrastructure Corp. ("**Steel Reef**") for total cash consideration of $500 million. Through the sale of these assets, Crescent Point monetized nine natural gas gathering and processing facilities and two gas sales pipelines currently in operation within Saskatchewan. These gas processing facilities and associated sales gas lines have a total throughput capacity of more than 90 MMcf/d. The assets did not include any oil-related infrastructure. Concurrently, Crescent Point entered into certain long-term take-or-pay commitments with Steel Reef in exchange for Steel Reef granting Crescent Point processing rights at the facilities.

On March 5, 2020, the Corporation announced the approval by the TSX of its notice to implement an NCIB to purchase, for cancellation, 36,884,438 Common Shares, or seven percent of the Corporation's public float, as at February 28, 2020. The 2020 NCIB commenced on March 9, 2020 and expired on March 8, 2021. No purchases were made under the NCIB.

On March 16, 2020, Crescent Point announced that (i) it had revised its 2020 capital expenditures budget to $700 to $800 million, which was expected to generate annual average production of 130,000 to 134,000 boe/d; (ii) it had revised its dividend from $0.01 per share payable every quarter to $0.0025 payable every quarter commencing in the second quarter of 2020; and (iii) all purchases under the NCIB had been deferred.

On April 20, 2020, Crescent Point announced that it had further revised its capital expenditures budget to approximately $650 to $700 million and lowered its production guidance for the year 2020 by 15%, primarily due to the voluntary shut-in of higher cost production.

On June 30, 2020, Crescent Point Holding Inc. transferred its interest in the Partnership to CPHL, a newly incorporated and wholly-owned subsidiary of Crescent Point. Crescent Point Energy Lux S.à r.l. was dissolved effective July 13, 2020.

On July 30, 2020, Myron Stadnyk was appointed to the Board. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

On September 1, 2020, Crescent Point announced that it had reactivated shut-in volumes, which reactivation resulted in expected second half 2020 production increasing by approximately 20 percent to 119,000 to 121,000 boe/d.

2021

On February 17, 2021, the Corporation entered into an agreement with Shell Canada Energy (“**Shell**”), an affiliate of Royal Dutch Shell plc, to acquire Shell’s Kaybob Duvernay assets in Alberta for $900 million. The total consideration consisted of $700 million in cash and 50 million Common Shares. The acquisition closed in April 2021.

On March 5, 2021, the Corporation announced the approval by the TSX of its notice to implement a NCIB (the "**2021 NCIB**") to purchase, for cancellation, 26,462,509 Common Shares, or five percent of the Corporation's public float, as at February 26, 2021. The NCIB commenced on March 9, 2021 and expired on March 8, 2022. The Corporation repurchased a total of 8,602,500 Common Shares under the 2021 NCIB program.

On June 7, 2021 the Corporation completed the disposition of its remaining non-core southeast Saskatchewan conventional assets, which were previously identified as disposition candidates, for cash proceeds of $93 million. As a result of the transaction, Crescent Point also reduced its asset retirement obligations by approximately $220 million, or nearly 25 percent of its asset retirement obligations balance as at March 31, 2021.

On September 13, 2021, the Corporation announced that it was increasing its quarterly dividend from $0.0025 per share payable every quarter to $0.03 per share payable every quarter, commencing with the fourth quarter of 2021.

On December 6, 2021, the Corporation announced that it was increasing its quarterly dividend from $0.03 per share payable every quarter to $0.045 per share payable every quarter, commencing with the first quarter of 2022.

CPHI, a former partner of the Partnership, was dissolved effective December 31, 2021.

2022

On March 4, 2022, the Corporation announced the approval by the TSX of its notice to implement a NCIB (the "**2022 NCIB**") to purchase, for cancellation, up to 57,309,975 Common Shares, or ten percent of the Corporation's public float, as at February 28, 2022. The NCIB commenced on March 9, 2022 and is due to expire on March 8, 2023. In 2022, the Corporation purchased 25,561,600 Common Shares under the 2022 NCIB. As of February 20, 2023, the Corporation had purchased an additional 2,526,900 Common Shares under the 2022 NCIB in 2023.

On May 12, 2022, the Corporation announced that it was increasing its quarterly dividend from $0.045 per share payable every quarter to $0.065 per share payable every quarter, commencing with the second quarter of 2022.

On May 19, 2022, Mindy Wight was elected to the Board. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

On October 26, 2022, the Corporation announced a special dividend of $0.035 per share payable on November 14, 2022.

On December 9, 2022, Crescent Point entered into an agreement to acquire Kaybob Duvernay assets from Paramount Resources Ltd. for cash consideration of $375 million. The acquisition closed in January 2023.

On December 9, 2022, the Corporation announced that it was increasing its quarterly dividend from $0.065 per share payable every quarter to $0.10 per share payable every quarter, commencing with the first quarter of 2023.

2023

On January 11, 2023, Crescent Point completed the acquisition of certain Kaybob Duvernay assets in Alberta for cash consideration of $370.6 million, including closing adjustments, which is expected to be allocated substantially to property, plant and equipment and exploration and evaluation. Cash consideration was funded primarily through cash on hand and included a deposit on acquisition of $18.7 million.

DESCRIPTION OF OUR BUSINESS

General

The Corporation is an oil and gas exploration, development and production company. The Corporation is a conventional oil and gas producer with assets strategically focused in properties comprised of high quality, long life, operated, light and medium crude oil, natural gas liquids and natural gas reserves in Western Canada and the United States. The primary assets of the Corporation are currently its interest in the Partnership, shares in CPHL, shares in CPUSH and, indirectly, shares in CPEUS.

The crude oil and natural gas properties and related assets generating income for the benefit of the Corporation are located in the provinces of Saskatchewan, Alberta, British Columbia and Manitoba and in the states of North Dakota and Montana. The properties and assets consist of producing crude oil, natural gas liquids and natural gas reserves and Proved plus Probable (as defined herein) crude oil, natural gas liquids and natural gas reserves not yet on production, and land holdings.

We pay regular cash dividends to Shareholders from our net cash flow in accordance with our dividend policy. Our primary sources of cash flow are distributions from the Partnership. During the year ended December 31, 2022, total dividends declared to shareholders were $0.36 per Common Share. See "*Dividends*".

Strategy

Our strategy is to deliver lasting market-leading value to our stakeholders as a trusted, ethical and environmentally responsible source for energy. We will maintain a resilient, balanced and sustainable portfolio, and apply our agile, diverse, learning mindset to optimize all aspects of our business.

We strive to enhance shareholder returns by cost effectively developing a focused asset base in a responsible and sustainable manner. The Corporation employs a disciplined capital allocation framework centered around returns and balance sheet strength, in order to create value for shareholders through a combination of significant return of capital, returns-based growth and balance sheet strength.

We strategically develop our properties through detailed technical analysis including reservoir characteristics, petroleum initially in place, recovery factors and the applicability of enhanced recovery techniques. Our development strategies include, multi-stage fracture stimulation of horizontal wells, infill and step-out wells, re-completion of existing wells along with the application of secondary and enhanced oil recovery techniques, including waterflood programs.

Risk Management and Marketing

Factors outside our control impact, to varying degrees, the prices we receive for production. These include, but are not limited to:

(a) world market forces, including world supply and consumption levels and the ability of OPEC+ and others to set and maintain production levels and prices for crude oil;
(b) political conditions, including the risk of hostilities in the Middle East, South America, Eastern Europe and other regions throughout the world;
(c) availability, proximity and capacity of take-away alternatives, including oil and gas gathering systems, pipelines, processing facilities, railcars and railcar loading facilities;
(d) increases or decreases in crude oil differentials and their implications for prices received by us;
(e) the impact of changes in the exchange rate between Canadian and U.S. dollars on prices received by us for our crude oil and natural gas;
(f) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the prices of crude oil and natural gas;
(g) global and domestic economic and weather conditions and changes in demand as a result of outbreaks or other health emergencies;
(h) price and availability of alternative energy sources;
(i) the effect of energy conservation measures and government regulations;
(j) U.S. and Canada tax policy; and
(k) pandemics, such as the COVID-19 health emergency.

Fluctuations in commodity prices, differentials and foreign exchange and interest rates, among other factors, are outside of our control and yet can have a significant impact on the level of cash we have available for return of capital to our shareholders, including payment of dividends and the acquisition of Common Shares.

To mitigate a portion of these risks, we actively initiate, manage and disclose the effects of our hedging activities. Our strategy for crude oil and natural gas production is to hedge up to 65%, or as otherwise approved by the Board of Directors, of our net of royalty production up to a rolling three and a half year basis, at the discretion of management. The Corporation also uses a combination of financial derivatives and fixed-differential physical contracts to hedge price differentials. For oil differential hedging, Crescent Point's risk management program allows for hedging a forward profile of up to three and a half years, and up to 35% net of royalty production. For gas differential hedging, Crescent Point's risk management program allows for hedging a forward profile of up to three and a half years, and up to 50% net of royalty production. All hedging activities are governed by our Risk Management and Counterparty Credit Policy and are regularly reviewed by the Board of Directors.

As part of our risk management program, benchmark oil prices are hedged using financial WTI-based instruments transacted in Canadian and U.S. dollars, benchmark natural gas prices are hedged using financial AECO-based instruments transacted in Canadian dollars. Total financial oil and gas hedges in 2022 amounted to approximately 43% of annual production, net of royalties, consisting of approximately 48% of annual liquids production and approximately 21% of annual natural gas production, net of royalties. The Corporation recorded a realized derivative loss on crude oil, NGL and natural gas hedge contracts of $641.8 million in 2022.

Crescent Point also enters into physical delivery and derivative WTI price differential contracts which manage the spread between US$ WTI and various stream prices on a portion of its production. The Corporation manages physical delivery contracts on a month-to-month spot and term contract basis. From January to December 2022, approximately 10,000 bbls/d of liquids production was contracted with fixed price differentials off WTI. Crescent Point also enters into derivative NYMEX price differential contracts which manage the spread between US$ NYMEX and AECO-based pricing on a portion of its natural gas production.

Refer to the annual financial statements for our commitments under all hedging agreements as at December 31, 2022.

In addition to hedging benchmark crude oil and natural gas prices with financial instruments, we also have the ability to mitigate crude oil basis risk by delivering a portion of our crude oil production into diversified refinery markets using rail transportation when it is economically beneficial to do so. Crescent Point operates two railcar loading facilities, serving its key producing areas of southeast Saskatchewan and southwest Saskatchewan. Crude oil and NGL volumes loaded at these facilities are sold at the loading facilities and our buyers are responsible for providing railcars and managing transportation logistics from that point until delivery.

We mitigate credit risk by having a well-diversified marketing portfolio for our commodity sales. Credit risk associated with the Corporation's product sales and with the Corporation's financial hedging portfolio is managed by Crescent Point's Risk Management Committee and is governed by a board-approved Risk Management and Counterparty Credit Policy that is reviewed annually by the Board of Directors. The Policy requires annual credit reviews of all trade counterparties. Credit limits are required to be set for all trade counterparties, which are based on either a fixed dollar amount which is set annually, at a minimum, or a percentage of the Corporation's portfolio calculated monthly. Crescent Point utilizes a diversified approach in both its physical sales portfolio and its financial hedging portfolio. The physical sales portfolio consists of 86 purchasers and its financial hedging portfolio consists of 10 counterparties. The Corporation's portfolio of counterparty exposures is monitored on a monthly basis.

To further mitigate credit risk associated with its physical sales portfolio, Crescent Point may obtain financial assurances such as parental guarantees, prepayments, letters of credit and third party credit insurance. Including these assurances, approximately 98% of the Corporation's oil and gas sales are with entities considered investment grade.

Revenue Sources

Our crude oil and natural gas volumes are sold in the United States, Saskatchewan, Alberta and British Columbia. During 2022, approximately 59% of our liquids volumes were sold in Saskatchewan, 26% in Alberta, 14% in the U.S. and less than 1% in British Columbia. Approximately 70% of our natural gas volumes were sold in Alberta, 20% in Saskatchewan, 9% in the United States and less than 1% in British Columbia.

For 2022, our commodity production mix was approximately 41% tight oil, 28% NGLs, 16% shale gas, 11% light and medium oil, 3% heavy oil and 1% conventional natural gas.

The following table summarizes our revenue sources by product before hedging and royalties:

For Year Ended	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas
2022	13.2%	3.2%	51.1%	24.9%	7.1%	0.5%
2021	15.4%	3.4%	55.8%	19.6%	5.3%	0.5%
2020	19.8%	3.6%	66.8%	5.4%	3.6%	0.8%

Competition

We actively compete for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than we do. Our competitors include major integrated oil and natural gas companies, numerous other independent oil and natural gas entities and individual producers and operators. Similarly, we face a competitive market when we attempt to divest of non-core assets.

Certain of our customers and potential customers are themselves exploring for crude oil and natural gas, and the results of such exploration efforts could affect our ability to sell or supply crude oil or natural gas to these customers in the future. Our ability to successfully bid on and acquire additional property rights, divest property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers is dependent upon developing and maintaining close working relationships with our industry partners and joint operators, our ability to select and evaluate suitable properties, and our ability to consummate transactions in a highly competitive environment.

Seasonal Factors

The production of crude oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

COVID-19 Pandemic

In response to the COVID-19 pandemic, the Corporation continues to monitor the situation and make adjustments to its health and safety protocols as required.

Crude oil and natural gas prices continued to strengthen in 2022, compared to the onset of the COVID-19 pandemic in 2020, as the global recovery from the COVID-19 pandemic and vaccine roll outs facilitated increased mobility, resulting in higher demand for crude oil and crude oil products and lower inventory levels.

Personnel

As of December 31, 2022, the Corporation had 768 permanent employees: 390 employees at the head office in Calgary, 12 employees working remotely in the U.S., 346 field employees in Canada and 20 field employees in the U.S.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

In accordance with NI 51-101, the reserves data of the Corporation set forth below (the "**Reserves Data**") is based upon evaluations conducted by McDaniel with an effective date of December 31, 2022 (the "**Crescent Point Reserve Report**"). The tables below are a combined summary of our crude oil, natural gas liquids, and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Crescent Point Reserve Report based on December 31, 2022 forecast price and cost assumptions using the average of three Independent Reserve Evaluators (McDaniel, GLJ Ltd. and Sproule Associates Ltd.). McDaniel evaluated the Corporation's total Proved plus Probable reserves and total Proved plus Probable value discounted at 10% and evaluated all of the Corporation's properties to prepare the Crescent Point Reserve Report. The tables below summarize the data contained in the Crescent Point Reserve Report.

The net present value of future net revenue attributable to our reserves is stated without provision for interest costs, and general and administrative costs, but after providing for estimated royalties, production costs, capital taxes, development costs, other income, future capital expenditures, projected carbon emission costs, and well and location abandonment costs. The reserve assessments also include costs associated with wells that have not been assessed values in the reserve reports and facilities and gathering systems associated with the ongoing production for the Corporation. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to our reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of our crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Corporation continuously monitors and reviews legislation concerning greenhouse gas emissions and the impact on operations. Legislation adopted in 2019 has allowed Crescent Point to reduce anticipated negative financial impacts from the production of oil and gas products through the Output-Based Performance Standard ("**OBPS**") program in Saskatchewan and the Technology Innovation and Emission Reduction ("**TIER**") program in Alberta. The carbon emission costs related to government programs are fully integrated into the operating costs and capital unit costs in the reserve evaluation.

The Crescent Point Reserve Report includes the abandonment, decommissioning, and reclamation costs for both the active and inactive locations, including all non-producing and suspended wells, facilities and pipelines. The incremental liabilities from the inactive locations on the total Proved plus Probable reserves is estimated at $208 million of value discounted at 10%. The total impact in the Crescent Point Reserve Report from the combined active and inactive liabilities on total Proved plus Probable reserves is estimated at $308 million of value discounted at 10%.

The Crescent Point Reserve Report is based on certain factual data supplied by Crescent Point as well as McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to Crescent Point's petroleum properties and contracts were supplied by the Corporation to McDaniel, and were accepted without any further investigation. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves[(1)]

	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil		Natural Gas Liquids		Shale Gas		Conventional Natural Gas		Total	
Reserves Category	Company Gross *(Mbbls)*	Company Net *(Mbbls)*	Company Gross *(Mbbls)*	Company Net *(Mbbls)*	Company Gross *(Mbbls)*	Company Net *(Mbbls)*	Company Gross *(Mbbls)*	Company Net *(Mbbls)*	Company Gross *(MMcf)*	Company Net *(MMcf)*	Company Gross *(MMcf)*	Company Net *(MMcf)*	Company Gross *(Mboe)*	Company Net *(Mboe)*
Proved Developed Producing														
Canada	38,102	33,802	18,986	15,886	101,184	94,938	67,238	58,433	248,748	228,852	35,719	32,243	272,920	246,575
United States	—	—	—	—	17,272	14,007	7,272	5,899	23,086	18,726	—	—	28,391	23,026
Total	38,102	33,802	18,986	15,886	118,455	108,945	74,510	64,332	271,834	247,578	35,719	32,243	301,312	269,601
Proved Developed Non-Producing														
Canada	337	323	2,323	2,108	342	320	2,148	1,749	12,140	10,967	69	59	7,185	6,339
United States	—	—	—	—	2,053	1,663	571	462	1,812	1,468	—	—	2,926	2,370
Total	337	323	2,323	2,108	2,395	1,984	2,719	2,211	13,953	12,435	69	59	10,111	8,709
Proved Undeveloped														
Canada	10,757	10,023	1,731	1,583	36,893	34,735	65,878	55,989	225,188	203,979	3,491	3,251	153,372	136,869
United States	—	—	—	—	11,913	9,649	3,375	2,734	10,714	8,678	—	—	17,073	13,829
Total	10,757	10,023	1,731	1,583	48,806	44,385	69,253	58,722	235,901	212,657	3,491	3,251	170,446	150,698
Total Proved														
Canada	49,197	44,148	23,039	19,578	138,419	129,994	135,264	116,171	486,076	443,798	39,279	35,553	433,478	389,782
United States	—	—	—	—	31,238	25,319	11,218	9,095	35,611	28,872	—	—	48,391	39,226
Total	49,197	44,148	23,039	19,578	169,657	155,313	146,482	125,266	521,688	472,670	39,279	35,553	481,868	429,008
Total Probable														
Canada	36,550	32,419	7,230	6,127	75,590	71,050	44,562	35,904	149,035	131,537	23,599	21,366	192,705	170,983
United States	—	—	—	—	25,788	20,896	8,330	6,751	26,445	21,433	—	—	38,525	31,219
Total	36,550	32,419	7,230	6,127	101,378	91,946	52,892	42,655	175,480	152,970	23,599	21,366	231,230	202,203
Total Proved Plus Probable														
Canada	85,747	76,567	30,268	25,705	214,009	201,044	179,827	152,075	635,111	575,335	62,877	56,919	626,182	560,766
United States	—	—	—	—	57,026	46,215	19,548	15,846	62,056	50,305	—	—	86,916	70,445
Total	85,747	76,567	30,268	25,705	271,034	247,259	199,374	167,920	697,167	625,640	62,877	56,919	713,098	631,211

Note:

(1) Numbers may not add due to rounding.

Net Present Value of Future Net Revenue of Oil and Gas Reserves[1]

	Before Income Taxes Discounted at (%/year)						After Income Taxes Discounted at (%/year)					
Reserves Category	0% (MM$)	5% (MM$)	8% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	8% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
Proved Developed Producing												
Canada	8,536	6,778	6,028	5,625	4,850	4,297	7,780	6,265	5,608	5,252	4,566	4,071
United States	871	752	696	664	598	547	858	743	689	657	593	543
Total	9,407	7,530	6,724	6,288	5,448	4,845	8,638	7,008	6,296	5,910	5,159	4,615
Proved Developed Non-Producing												
Canada	277	209	183	170	146	129	208	156	138	128	111	99
United States	129	115	109	106	99	93	123	111	105	102	95	90
Total	406	324	293	276	245	222	331	267	243	230	206	188
Proved Undeveloped												
Canada	4,346	2,958	2,393	2,092	1,522	1,130	3,283	2,175	1,726	1,487	1,037	731
United States	434	341	299	275	227	189	404	315	275	252	205	170
Total	4,779	3,299	2,692	2,367	1,749	1,319	3,686	2,490	2,001	1,739	1,243	901
Total Proved												
Canada	13,159	9,945	8,605	7,887	6,518	5,557	11,270	8,596	7,471	6,867	5,714	4,901
United States	1,433	1,208	1,104	1,045	923	829	1,385	1,169	1,069	1,011	894	803
Total	14,592	11,153	9,709	8,932	7,441	6,386	12,655	9,765	8,540	7,878	6,607	5,704
Total Probable												
Canada	8,152	4,487	3,375	2,854	1,990	1,476	6,171	3,368	2,516	2,118	1,460	1,071
United States	1,227	883	747	675	538	443	987	702	590	531	421	344
Total	9,380	5,370	4,121	3,528	2,528	1,919	7,158	4,070	3,106	2,649	1,881	1,415
Total Proved Plus Probable												
Canada	21,312	14,432	11,980	10,741	8,508	7,033	17,442	11,964	9,988	8,985	7,173	5,973
United States	2,660	2,091	1,851	1,719	1,461	1,272	2,372	1,871	1,659	1,543	1,314	1,147
Total	23,972	16,523	13,831	12,460	9,969	8,305	19,813	13,835	11,646	10,528	8,488	7,120

Note:

(1) Numbers may not add due to rounding.

Additional Information Concerning Future Net Revenue – (Undiscounted)[(1)]

Reserves Category	Revenue (MM$)	Royalties & Burdens[(2)] (MM$)	Operating Costs (MM$)	Development Costs (MM$)	Abandonment and Reclamation Costs[(3)] (MM$)	Future Net Revenue Before Income Taxes (MM$)	Income Tax (MM$)	Future Net Revenue After Income Taxes (MM$)
Proved								
Canada	33,876	3,925	12,205	3,089	1,497	13,159	1,889	11,270
United States	3,927	1,012	1,130	315	37	1,433	48	1,385
Total	37,803	4,937	13,336	3,404	1,534	14,592	1,937	12,655
Proved Plus Probable								
Canada	51,653	6,164	18,075	4,448	1,655	21,312	3,870	17,442
United States	7,228	1,867	1,958	696	46	2,660	288	2,372
Total	58,881	8,031	20,033	5,145	1,701	23,972	4,158	19,813

Notes:

(1) Numbers may not add due to rounding.

(2) Saskatchewan Capital Resource Surcharge, as well as Ad Valorem, have been included under the royalties and burdens column.

(3) In accordance with the Canadian Oil and Gas Evaluation Handbook, abandonment and reclamation costs include: (i) entities with associated reserves included in the Crescent Point Reserve Report, the undiscounted abandonment and reclamation costs associated with these amounts to $843 million and $1.0 billion for Proved and Proved plus Probable, respectively; and (ii) non-reserve entities that include wells with no reserves assigned, suspended wells, pipeline, and facilities, the undiscounted abandonment and reclamation costs associated with these are estimated at $691 million.

Future Net Revenue by Production Type[(1)]

	Future Net Revenue Before Income Taxes[2] (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved				
CANADA				
Light and Medium Crude Oil[3]	1,037	13.1	19.85	3.31
Heavy Crude Oil[3]	398	5.0	20.19	3.36
Tight Oil[5]	3,259	41.3	18.88	3.15
Shale Gas[6]	3,144	39.9	22.66	3.78
Conventional Natural Gas[4]	50	0.6	7.76	1.29
Total Canada	7,887	100	20.23	3.37
UNITED STATES				
Light and Medium Crude Oil[3]	—	—	—	—
Heavy Crude Oil[3]	—	—	—	—
Tight Oil[5]	1,045	100	26.63	4.44
Shale Gas[4][6]	—	—	—	—
Conventional Natural Gas[4]	—	—	—	—
Total United States	1,045	100	26.63	4.44
TOTAL				
Light and Medium Crude Oil[3]	1,037	11.6	19.85	3.31
Heavy Crude Oil[3]	398	4.5	20.19	3.36
Tight Oil[5]	4,303	48.2	20.31	3.39
Shale Gas[4][6]	3,144	35.2	22.66	3.78
Conventional Natural Gas[4]	50	0.6	7.76	1.29
Total Proved	8,932	100	20.82	3.47

Notes:

(1) Numbers may not add due to rounding.

(2) Other company revenue and costs not related to a specific production type have been allocated proportionately to production types. Unit values are based on Company Net Reserves.

(3) Including solution gas and other by-products.

(4) Including by-products, but excluding solution gas.

(5) Including solution gas (categorized as "Shale Gas") and other by-products.

(6) Shale Gas includes the majority of Natural Gas Liquids.

	Future Net Revenue Before Income Taxes[2] (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	(%)	($/boe)	($/Mcfe)
Proved Plus Probable				
CANADA				
Light and Medium Crude Oil[3]	1,710	15.9	18.13	3.02
Heavy Crude Oil[3]	493	4.6	19.06	3.18
Tight Oil[5]	4,752	44.2	18.13	3.02
Shale Gas[6]	3,730	34.7	21.84	3.64
Conventional Natural Gas[4]	57	0.5	7.29	1.22
Total Canada	10,741	100	19.15	3.19
UNITED STATES				
Light and Medium Crude Oil[3]	—	—	—	—
Heavy Crude Oil[3]	—	—	—	—
Tight Oil[5]	1,719	100	24.40	4.07
Shale Gas[4][6]	—	—	—	—
Conventional Natural Gas[4]	—	—	—	—
Total United States	1,719	100	24.40	4.07
TOTAL				
Light and Medium Crude Oil[3]	1,710	13.7	18.13	3.02
Heavy Crude Oil[3]	493	4.0	19.06	3.18
Tight Oil[5]	6,471	51.9	19.46	3.24
Shale Gas[4][6]	3,730	29.9	21.84	3.64
Conventional Natural Gas[4]	57	0.5	7.29	1.22
Total Proved Plus Probable	12,460	100	19.74	3.29

Notes:

(1) Numbers may not add due to rounding.

(2) Other company revenue and costs not related to a specific production type have been allocated proportionately to production types. Unit values are based on Company Net Reserves.

(3) Including solution gas and other by-products.

(4) Including by-products, but excluding solution gas.

(5) Including solution gas (categorized as "Shale Gas") and other by-products.

(6) Shale Gas includes the majority of Natural Gas Liquids.

Notes and Definitions

In the tables set forth above in "*Disclosure of Reserves Data*" and elsewhere in this AIF, the following notes and other definitions are applicable.

Reserve Categories

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of Proved and Probable reserves have been established in accordance with NI 51-101 to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

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

(b) "**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.

(c) "**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.

(d) "**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.

(e) "**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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 category (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

(f) **"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.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve 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 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.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional Definitions

The following terms, used in the preparation of the Crescent Point Reserve Report and this AIF, have the following meanings:

(a) "**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

(b) "**crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain small amounts of sulphur and other non-hydrocarbons, that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. It does not include liquids obtained from the processing of natural gas.

(c) "**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(ii) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(iii) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds measuring devices and production storage, natural gas cycling and processing plants, and central utility and waste disposal system; and

(iv) provide improved recovery systems.

(d) "**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

(e) "**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;

(iii) dry hole contributions and bottom hole contributions;

(iv) costs of drilling and equipping exploratory wells; and

(v) costs of drilling exploratory type stratigraphic test wells.

(f) "**exploratory well**" means a well that is not a development well, a service well or a development type stratigraphic test well.

(g) "**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field.

The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

(h) "**future prices and costs**" means future prices and costs that are:

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

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

(i) "**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(i) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(ii) without deducting estimated future costs that are not deductible in computing taxable income;

(iii) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(iv) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year end statutory tax rates, taking into account future tax rates already legislated.

(j) "**future net revenue**" means the estimated net amount to be received with respect to the anticipated development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using future prices and costs.

(k) "**gross**" means:

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

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

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

(l) "**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases.

(m) "**natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

(n) "**net**" means:

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

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

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

(o) "**non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

(p) "**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities as well as other costs of operating and maintaining those wells and related equipment and facilities.

(q) "**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

(r) "**property**" includes:

(i) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(ii) royalty interests, production payments payable in oil or gas, and other non-operated interests in properties operated by others; and

(iii) an agreement with a foreign government or authority under which the Corporation participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

(s) "**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(i) costs of lease bonuses and options to purchase or lease a property;

(ii) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(iii) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

(t) "**proved property**" means a property or part of a property to which reserves have been specifically attributed.

(u) "**reservoir**" means a subsurface rock unit that contains an accumulation of petroleum.

(v) "**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

(w) "**solution gas**" means natural gas dissolved in crude oil.

(x) "**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) "exploratory type" if not drilled into a proved property; or (ii) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

(y) "**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

(z) "**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

(aa) "**well abandonment and reclamation costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system and remediating and reclaiming the site to original conditions. They do not include costs of abandoning the gathering system.

Pricing Assumptions – Forecast Prices and Costs

The average of the three independent reserve evaluator price decks (McDaniel, GLJ Ltd., and Sproule Associates Ltd.) resulted in the following pricing, exchange rate and inflation rate assumptions as of December 31, 2022 in estimating our reserves data using forecast prices and costs.

Year	Crude Oil		Conventional Natural Gas		NGLs					
	WTI at Cushing Oklahoma *($US/bbl)*	Edmonton *($Cdn/bbl)*	Henry Hub NYMEX *($US/MMBTU)*	AECO/NIT Spot *($Cdn/MMBTU)*	Pentane Plus Edmonton *($Cdn/bbl)*	Butane Edmonton *($Cdn/bbl)*	Propane Edmonton *($Cdn/bbl)*	Operating Cost Inflation Rate *(%/yr)*	Capital Cost Inflation Rate *(%/yr)*	Exchange Rate *($US/$Cdn)*
Forecast										
2023	80.33	103.76	4.74	4.23	106.22	53.88	39.80	0.0%	0.0%	0.745
2024	78.50	97.74	4.50	4.40	101.35	52.67	39.14	2.3%	2.3%	0.765
2025	76.95	95.27	4.31	4.21	98.94	51.42	39.74	2.0%	2.0%	0.768
2026	77.61	95.58	4.40	4.27	100.19	51.61	39.86	2.0%	2.0%	0.772
2027	79.16	97.07	4.49	4.34	101.74	52.39	40.47	2.0%	2.0%	0.775
2028	80.74	99.01	4.58	4.43	103.78	53.44	41.28	2.0%	2.0%	0.775
2029	82.36	100.99	4.67	4.51	105.85	54.51	42.11	2.0%	2.0%	0.775
2030	84.00	103.01	4.76	4.60	107.97	55.60	42.95	2.0%	2.0%	0.775
2031	85.69	105.07	4.86	4.69	110.13	56.71	43.81	2.0%	2.0%	0.775
2032	87.40	106.69	4.95	4.79	112.33	57.56	44.47	2.0%	2.0%	0.775
2033	89.15	108.83	5.05	4.88	114.58	58.71	45.35	2.0%	2.0%	0.775
2034+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0%	2.0%	0.775

Reconciliations of Changes in Reserves[1]

The following table sets forth a reconciliation of the Corporation's working interest reserves by total Proved, total Probable and total Proved plus Probable reserves as at December 31, 2022, against such reserves as at December 31, 2021, based on forecast price and cost assumptions.

CANADA	Light and Medium Crude Oil *(Mbbls)*			Heavy Crude Oil *(Mbbls)*			Tight Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	61,122	40,574	101,696	24,259	7,255	31,514	147,930	81,170	229,100	118,638	39,126	157,764
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	2,000	741	2,741	93	30	123	2,511	(178)	2,333	20,614	5,283	25,896
Technical Revisions [3]	(1,115)	(2,301)	(3,416)	(447)	(157)	(605)	1,623	(4,778)	(3,154)	3,378	(812)	2,566
Acquisitions [4]	—	—	—	—	—	—	28	8	36	10,016	2,481	12,496
Dispositions [5]	(9,052)	(3,046)	(12,098)	—	—	—	(710)	(1,023)	(1,733)	(7,065)	(1,824)	(8,890)
Economic Factors [6]	1,453	582	2,034	603	102	706	2,416	391	2,807	1,353	310	1,662
Production [7]	(5,210)	—	(5,210)	(1,470)	—	(1,470)	(15,379)	—	(15,379)	(11,668)	—	(11,668)
December 31, 2022	49,197	36,550	85,747	23,039	7,230	30,268	138,419	75,590	214,009	135,264	44,562	179,827

CANADA	Shale Gas (Natural Gas) *(MMcf)*			Conventional Natural Gas (Natural Gas) *(MMcf)*			Total BOE *(Mboe)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	408,722	131,140	539,862	43,612	25,077	68,690	427,338	194,161	621,500
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	90,983	22,017	113,000	684	299	983	40,496	9,595	50,090
Technical Revisions [3]	2,357	(9,583)	(7,226)	(2,149)	(1,955)	(4,104)	3,473	(9,971)	(6,498)
Acquisitions [4]	61,384	15,280	76,664	—	—	—	20,274	5,035	25,309
Dispositions [5]	(38,086)	(10,679)	(48,765)	(1,290)	(371)	(1,661)	(23,390)	(7,735)	(31,125)
Economic Factors [6]	3,646	860	4,506	2,247	549	2,796	6,806	1,620	8,426
Production [7]	(42,930)	—	(42,930)	(3,826)	—	(3,826)	(41,520)	—	(41,520)
December 31, 2022	486,076	149,035	635,111	39,279	23,599	62,877	433,478	192,705	626,182

UNITED STATES	Light and Medium Crude Oil *(Mbbls)*			Heavy Crude Oil *(Mbbls)*			Tight Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	—	—	—	—	—	—	33,615	26,698	60,314	11,391	8,616	20,007
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions [3]	—	—	—	—	—	—	838	(1,318)	(480)	1,033	(441)	592
Acquisitions	—	—	—	—	—	—	111	35	146	31	13	44
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors [6]	—	—	—	—	—	—	953	373	1,326	438	142	580
Production [7]	—	—	—	—	—	—	(4,280)	—	(4,280)	(1,675)	—	(1,675)
December 31, 2022	—	—	—	—	—	—	31,238	25,788	57,026	11,218	8,330	19,548

UNITED STATES	Shale Gas (Natural Gas) *(MMcf)*			Conventional Natural Gas (Natural Gas) *(MMcf)*			Total BOE *(Mboe)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	36,162	27,353	63,515	—	—	—	51,033	39,873	90,907
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery	—	—	—	—	—	—	—	—	—
Technical Revisions [3]	2,810	(1,400)	1,410	—	—	—	2,339	(1,993)	347
Acquisitions	98	42	139	—	—	—	158	55	213
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors [6]	1,391	450	1,841	—	—	—	1,623	590	2,213
Production [7]	(4,849)	—	(4,849)	—	—	—	(6,763)	—	(6,763)
December 31, 2022	35,611	26,445	62,056	—	—	—	48,391	38,525	86,916

TOTAL	Light and Medium Crude Oil *(Mbbls)*			Heavy Crude Oil *(Mbbls)*			Tight Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	61,122	40,574	101,696	24,259	7,255	31,514	181,545	107,868	289,413	130,029	47,742	177,772
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	2,000	741	2,741	93	30	123	2,511	(178)	2,333	20,614	5,283	25,896
Technical Revisions [3]	(1,115)	(2,301)	(3,416)	(447)	(157)	(605)	2,462	(6,096)	(3,634)	4,410	(1,253)	3,157
Acquisitions [4]	—	—	—	—	—	—	139	43	182	10,046	2,494	12,540
Dispositions [5]	(9,052)	(3,046)	(12,098)	—	—	—	(710)	(1,023)	(1,733)	(7,065)	(1,824)	(8,890)
Economic Factors [6]	1,453	582	2,034	603	102	706	3,368	764	4,133	1,791	451	2,242
Production [7]	(5,210)	—	(5,210)	(1,470)	—	(1,470)	(19,659)	—	(19,659)	(13,343)	—	(13,343)
December 31, 2022	49,197	36,550	85,747	23,039	7,230	30,268	169,657	101,378	271,034	146,482	52,892	199,374

TOTAL	Shale Gas (Natural Gas) *(MMcf)*			Conventional Natural Gas (Natural Gas) *(MMcf)*			Total BOE *(Mboe)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	444,884	158,493	603,377	43,612	25,077	68,690	478,371	234,035	712,406
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (2)	90,983	22,017	113,000	684	299	983	40,496	9,595	50,090
Technical Revisions (3)	5,167	(10,983)	(5,816)	(2,149)	(1,955)	(4,104)	5,813	(11,964)	(6,151)
Acquisitions (4)	61,482	15,322	76,804	—	—	—	20,432	5,090	25,523
Dispositions (5)	(38,086)	(10,679)	(48,765)	(1,290)	(371)	(1,661)	(23,390)	(7,735)	(31,125)
Economic Factors (6)	5,037	1,310	6,347	2,247	549	2,796	8,429	2,209	10,639
Production (7)	(47,779)	—	(47,779)	(3,826)	—	(3,826)	(48,283)	—	(48,283)
December 31, 2022	521,688	175,480	697,167	39,279	23,599	62,877	481,868	231,230	713,098

Notes:

(1) Numbers may not add due to rounding.

(2) The Corporation's Canadian development strategy focused on continued development of its Kaybob Duvernay asset, along with low risk, infill and development, primarily in the Viewfield, Flat Lake, and Shaunavon resource plays. The Corporation continues its decline mitigation efforts through implementation of waterflood development within its Saskatchewan assets.

(3) The Corporation realized minor positive, performance related revisions in both Canada and the United States. These were offset by negative revisions due to increased operating expenses, as a result of inflationary pressures on costs. Overall, total revisions made up a minor portion of the year-over-year changes.

(4) The Corporation completed a property acquisition and a land swap within its Kaybob Duvernay asset. On January 11, 2023, after the effective date of the reserve report, the Corporation closed an additional acquisition of lands in the Kaybob area for cash consideration of $370.6 million, including closing adjustments. Due to this timing, reserves for these assets are not included in the year-end 2022 reserves.

(5) The Corporation completed dispositions of non-core Southwest Saskatchewan Viking asset, portions of its East Shale Basin Duvernay asset, as well as a land swap within its Kaybob Duvernay asset.

(6) Increases in reserves are due to increases in forecast commodity prices, determined by prior year end reserves calculated on current year end price forecasts.

(7) The Corporation produced an average of 113,752 boe per day in Canada, 18,530 boe per day in the United States for a total of 132,282 boe per day.

Undeveloped Reserves

The following discussion generally describes the basis on which we attribute Proved and Probable undeveloped reserves. Our near-term plans for developing our undeveloped reserves are described in the section "*Major Oil and Gas Properties*".

Proved Undeveloped Reserves

Proved Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves represent a high degree of certainty to be recoverable, and mostly relate to planned infill drilling and proximal offset locations to current producing entities.

The Corporation has extensive Proved development opportunities that are prioritized based on a disciplined set of criteria including, but not limited to, time for payout, rate of return, maturity of land tenure, reserve booking opportunities, proximity to transportation and marketing, as well as anticipated production rates. With this extensive portfolio of opportunities, it would be unrealistic, both from a cash flow as well as a physical ability, to completely execute on the entire portfolio of booked opportunities within two years, however, approximately 41% of the development spending occurs within this time frame.

The development of these reserves have been based on current and planned capital activity levels, with no material deferrals of development opportunities beyond these normal budgetary constraints. The majority of these reserves are planned to be developed within a three year time frame, which represents approximately 58% of the net undeveloped location count, as well as 63% of the net total future development capital. These development activities are directed mostly to the Corporation's core focus areas of Kaybob Duvernay, Viewfield Bakken, Flat Lake Torquay and Shaunavon resource plays in Canada and the North Dakota Bakken play in the U.S. The current market environment has resulted in long term sustainability. When combined with an extensive location inventory, this results in an extended time period for full development.

The following table provides the timing of the initial reserve assignments for the Corporation's gross Proved Undeveloped reserves.

Timing of Initial Proved Undeveloped Reserve Assignment

	Light & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Tight Oil (Mbbl)		Natural Gas Liquids (Mbbl)		Shale Gas (MMcf)		Conventional Natural Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed(1)	Total at Year-End	First Attributed(1)	Total at Year-End	First Attributed(1)	Total at Year-End	First Attributed(1)	Total at Year-End	First Attributed(1)	Total at Year-End	First Attributed(1)	Total at Year-End	First Attributed(1)	Total at Year-End
2020	120	22,242	—	1,420	1,377	79,190	98	19,422	170	70,873	148	10,224	1,647	135,790
2021	4,784	14,353	404	1,677	8,960	61,755	44,358	57,577	137,175	183,576	987	3,468	81,533	166,536
2022	1,108	10,757	—	1,731	167	48,806	25,624	69,253	117,568	235,901	528	3,491	46,581	170,446

Note:

(1) "First attributed" refers to reserves first attributed at year-end to corresponding fiscal year.

Probable Undeveloped Reserves

Probable Undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, and lands contiguous to production. These reserves represent quantities that are less certain to be recovered than Proved reserves.

In the reserve evaluation, development of these reserves is balanced across a five to seven year time-frame to closely match the aggregate internal development schedule and represent a practicable development program. The majority of these reserves are planned to be developed within a three year time frame, representing approximately 45% of the net undeveloped location count, as well as 55% of the total net future development costs. The current market environment has resulted in long term sustainability. When combined with extensive location inventory, this results in an extended full development time period.

This broader distribution of development activities continues to focus on the Corporation's core areas, while reclassifying current Probable locations to Proved locations during the early years of development. These development activities are directed mostly to the Corporation's core focus areas of Kaybob Duvernay, Viewfield Bakken, Flat Lake Torquay and Shaunavon resource plays in Canada and the North Dakota Bakken play in the U.S.

The following table provides the timing of the initial reserve assignments for the Corporation's Probable Undeveloped reserves.

Timing of Initial Probable Undeveloped Reserves Assignment

	Light & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Tight Oil (Mbbl)		Natural Gas Liquids (Mbbl)		Shale Gas (MMcf)		Conventional Natural Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed[(1)]	Total at Year-End	First Attributed[(1)]	Total at Year-End	First Attributed[(1)]	Total at Year-End	First Attributed[(1)]	Total at Year-End	First Attributed[(1)]	Total at Year-End	First Attributed[(1)]	Total at Year-End	First Attributed[(1)]	Total at Year-End
2020	217	31,681	—	1,065	3,753	82,972	437	19,951	1,725	68,679	313	16,844	4,746	149,923
2021	1,190	24,862	693	1,447	1,466	66,758	9,084	27,067	26,750	80,377	640	14,767	16,998	135,991
2022	470	23,332	—	1,481	57	60,050	6,384	29,544	29,397	91,012	236	14,877	11,849	132,055

Note:

(1) "First attributed" refers to reserves first attributed at year end of the corresponding fiscal year.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Our reserves are evaluated by McDaniel, an independent engineering firm. Different reserve engineers may make different estimates of reserve quantities based on the same data.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions and judgments, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from numerous factors including, but not limited to, additional development activity, evolving production history, continual reassessment of the viability of production under varying economic conditions, changes in forecast prices, and reservoir performance. Such revisions can be substantial and can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to total Proved reserves and total Proved plus Probable reserves (using forecast prices and costs).

Company Annual Capital Expenditures (MM$)						
	Canada (2)		United States (3)		Total (1)	
Year	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable
2023	468	521	271	401	739	922
2024	608	732	36	232	644	964
2025	763	898	8	63	771	962
2026	624	725	—	—	624	725
2027	552	702	—	—	552	702
2028	52	652	—	—	52	652
2029	4	201	—	—	4	201
2030	5	5	—	—	5	5
2031	6	6	—	—	6	6
2032	2	2	—	—	2	2
2033	1	1	—	—	1	1
2034	1	1	—	—	1	1
Subtotal(1)	3,087	4,446	315	696	3,402	5,143
Remainder	2	2	—	—	2	2
Total(1)	3,089	4,448	315	696	3,404	5,145
10% Discounted	2,432	3,327	293	626	2,724	3,953

Notes:

(1) Numbers may not add due to rounding.

(2) Due to the nature of the resource style plays that Crescent Point is focused on, with large contiguous blocks of land, a large number of Proved as well as Proved plus Probable locations have been booked. The scheduling of locations in the reserve report have a similar drilling timing as the Corporation's long-term development plan, with development drilling scheduled to occur within a five year period for Proved reserves, extending up to seven year for Probable reserves.

(3) As in Canada, a large number of Proved as well as Proved plus Probable locations have been booked. The scheduling of locations in the reserve report have a similar drilling timing as the Corporation's long-term development plan, with development drilling scheduled to occur within a three year period for Proved and Probable reserves.

We estimate that our internally generated cash flow will be sufficient to fund the future development costs ("**FDC**") disclosed above. In addition, we have access to debt financing through our bank credit facilities and through debt capital markets, if available on terms acceptable to us.

Major Oil and Gas Properties

The following is a description of the major oil and natural gas producing properties in which Crescent Point has an interest and that are material to the Corporation's operations and activities. All of the Corporation's assets are located onshore within North America. The

Corporation holds no interests in any plants, facilities or installations that are significant beyond normal oil and gas operating practices. Unless otherwise noted, reserve amounts are Company Gross, based on escalating cost and price assumptions as evaluated in the Crescent Point Reserve Report as at December 31, 2022.

Kaybob Area

Kaybob Duvernay production is a combination of natural gas liquids and natural gas, weighted approximately 59% to natural gas liquids. The play is being developed using multi-staged fractured horizontal wells. In 2022, Crescent Point's gross production averaged approximately 37,000 boe per day. 2022 production was made up of approximately 47% condensate. In 2022, the Corporation expanded its Kaybob Duvernay assets with the acquisition of certain Duvernay assets from Repsol Oil & Gas Canada Inc.

In Kaybob, the Corporation spent $281.1 million, representing 29% of its 2022 capital program, drilling 23 (23 net) horizontal wells.

At year-end 2022, the Corporation's Total Proved plus Probable reserves in Kaybob were 202.6 MMboe, with 126 (126 net) drilling locations booked, representing approximately 28% of the Corporation's total Proved plus Probable reserves. It is expected the Total Proved as well as the Total Proved plus Probable locations will be developed within five years.

As of December 31, 2022, Crescent Point has allocated approximately 32% of the Corporation's 2023 capital budget to developing the Duvernay resource play in Kaybob.

On January 11, 2023, Crescent Point completed the acquisition of certain Kaybob Duvernay assets in Alberta for cash consideration of $370.6 million, including closing adjustments.

North Dakota Area

In North Dakota, the Corporation is developing the Bakken resource play, in which the production is a high-quality light oil and is developed using multi-staged fractured horizontal wells. In 2022, Crescent Point's gross production averaged approximately 19,000 boe per day.

In North Dakota, the Corporation spent $258.9 million, representing 27% of its 2022 capital program, drilling 34 (32.2 net) horizontal wells.

At year-end 2022, the Corporation's Total Proved plus Probable reserves in North Dakota were 86.9 MMboe, with 105 (67.7 net) locations booked, representing approximately 12% of the Corporation's total Proved plus Probable reserves. It is expected the Total Proved as well as the Total Proved plus Probable locations will be developed within five years.

As of December 31, 2022, Crescent Point has allocated approximately 35% of the Corporation's 2023 capital budget to developing the Bakken resource play in North Dakota.

Viewfield Area

The Viewfield resource area, located in southeastern Saskatchewan, has development in the Bakken resource play, as well as conventional plays including the Frobisher and Midale. In 2022, Crescent Point's production averaged approximately 31,000 boe per day in the area. The majority of production is from the Bakken resource which is a high quality light oil and is exploited using multi-fractured horizontal wells. The core area of the Bakken resource has mostly been unitized, which has allowed for the implementation of various waterflood projects.

Crescent Point spent $165.3 million, representing approximately 17% of its 2022 capital development program, in the Viewfield area including drilling 71 (69.6 net) additional oil wells. The Corporation also continued to focus on waterflood development expansion.

At year-end 2022, the Corporation's total Proved plus Probable reserves in the Viewfield area were 182.9 MMboe, with 630 (588.2 net) locations booked to these reserves. This represents approximately 26% of the Corporation's total Proved plus Probable reserves. Crescent Point expects to fully develop this location inventory within five years for Proved reserves, extending to six years for Probable reserves.

As of December 31, 2022, Crescent Point has allocated approximately 13% of the Corporation's 2023 capital budget to development of the Viewfield area, focused on the Bakken resource play and conventional Frobisher and Midale drilling, as well as additional waterflood development.

Shaunavon Area

The Shaunavon resource area, located in southwest Saskatchewan, has development occurring in the Upper and Lower Shaunavon resource zones, as well as conventional Upper Shaunavon pools, all of which are medium quality oil. The tight oil Upper and Lower resource plays have been developed using multi-stage fracture stimulated horizontal wells. In 2022, Crescent Point's production averaged approximately 19,000 boe per day in the area.

Crescent Point spent $177.9 million, representing approximately 19% of its 2022 capital development program, in the Shaunavon area including drilling 69 (62.2 net) additional wells. The Corporation has also continued to focus on waterflood expansion and has also initiated a new enhanced oil recovery project in a conventional Upper Shaunavon pool.

As of year-end 2022, the Corporation's total Proved plus Probable reserves in the Shaunavon area were 105.9 MMboe, with 501 (487.5 net) locations booked to these reserves. This represents approximately 15% of the Corporation's total Proved plus Probable reserves. Crescent Point expects to fully develop this location inventory within five years for Proved reserves, extending to seven years for Probable reserves.

As of December 31, 2022, Crescent Point has allocated approximately 9% of the Corporation's 2023 capital budget to development of the Shaunavon area, focused on both Upper and Lower Shaunavon drilling, as well as continued expansion of waterflood and polymer enhanced oil recovery projects.

Oil and Gas Wells

Producing Wells				
Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Saskatchewan	5,293	4,733	55	17
Alberta	259	219	407	378
British Columbia	8	5	—	—
TOTAL CANADA	5,560	4,957	462	395
U.S.				
North Dakota	218	175	—	—
TOTAL U.S.	218	175	—	—
Total	5,778	5,132	462	395

Non-Producing Wells				
Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Saskatchewan	3,166	2,624	426	139
Alberta	439	338	169	149
British Columbia	1	1	—	—
TOTAL CANADA	3,606	2,963	595	288
U.S.				
North Dakota	32	28	—	—
TOTAL U.S.	32	28	—	—
Total	3,638	2,991	595	288

Notes:

(1) Gross and net producing and non-producing oil and gas counts include both reserve assigned and non-reserve assigned wells.

(2) Active injection wells are reflected in the non-producing well count.

All of the Corporation's oil and gas wells are onshore. Non-producing wells are generally situated within defined developed areas and include recent drills awaiting final preparation prior to being placed on production; existing wells that may be waiting on improved economic conditions to restart; wells currently in use for observation or monitoring; wells awaiting recompletion in secondary zones or as injectors; or wells scheduled for abandonment. These non-producing entities include wells with reserve assignments as well as currently non-booked wells, which will have various terms of being non-producing from recent to longer-term.

Developed non-producing reserves represent only 2% of the Total Proved reserve category, and 1% of the Total Proved plus Probable reserve category. Wells in the developed non-producing category exist across most of the Corporation's areas and mostly represent wells awaiting final preparation for production, plus those awaiting well reactivation.

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which we have an interest and also the number of net acres for which our rights to develop or exploit will, absent further action, expire within one year.

	As of December 31, 2022		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
CANADA			
Alberta	465,620	431,196	67,758
Saskatchewan	592,468	556,338	52,210
Manitoba	2,475	2,475	—
British Columbia	30,610	18,429	—
Total	1,091,173	1,008,438	119,968
U.S.			
North Dakota	20,713	15,278	—
Total	20,713	15,278	—
Total	1,111,886	1,023,716	119,968

The Corporation has no material drilling commitments relating to unproved properties.

Drilling Activity

The following table summarizes the gross and net exploration and development wells in which we participated during the year ended December 31, 2022, in each of Canada and the United States.

	Development Wells		Exploration Wells [2]		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil wells	162	151	—	—	162	151
Natural Gas wells	23	23	—	—	23	23
Service wells	—	—	—	—	—	—
Stratigraphic test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total [1]	185	174	—	—	185	174

	Development Wells		Exploration Wells [2]		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Oil wells	33	31	—	—	33	31
Natural Gas wells	—	—	—	—	—	—
Service wells	1	1	—	—	1	1
Stratigraphic Test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total [1]	34	32	—	—	34	32

Notes:

(1) Numbers may not add due to rounding.

(2) Exploration wells in this grouping are based on the well license classification at the time of drilling.

For details on important exploration and development activities during 2022, see "*Statement of Reserves Data and Other Oil and Gas Information – Major Oil and Gas Properties*".

The Corporation has no work commitments for its proved properties (including drilling commitments) in Canada or the U.S. for the next three years.

Tax Horizon

Crescent Point had tax pools of approximately $8.7 billion at December 31, 2022, which are deductible against future taxable income. Based on this tax pool balance and forecast cash flows using December 31, 2022 forecast prices from the average of three Independent Reserve Evaluators (McDaniel, GLJ Ltd. and Sproule Associates Ltd.), with the Corporation's development capital plans, Crescent Point expects to pay income taxes in 2024 of approximately 1% of its forecast cash flow from operations. Crescent Point is subject to other taxes, such as ad valorem taxes, severance taxes, payroll taxes, property taxes, carbon taxes, sales taxes and foreign withholding taxes as part of its ongoing business.

Costs Incurred(1)

The following table summarizes our property acquisition costs, exploration costs and development costs for the year ended December 31, 2022. The total capital costs were approximately $975.3 million in 2022.

($ millions)	Acquisition Costs (2)			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Canada	61.0	28.1	9.4	707.1
U.S.	1.6	—	—	258.8
Total	62.6	28.1	9.4	965.9

Notes:

(1) Costs incurred exclude capitalized administration.

(2) Excludes disposition proceeds of $272.7 million and $10.9 million for proved and unproved properties, respectively.

Production Estimates

The following table discloses for each product type the gross volume of production estimated by McDaniel for 2023 in the estimates of future net revenue with forecast pricing from Proved reserves disclosed above under the heading "*Reserves Data – Forecast Prices and Costs*".

	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas	Total
	(bbls/d)	*(bbls/d)*	*(bbls/d)*	*(bbls/d)*	*(Mcf/d)*	*(Mcf/d)*	*(boe/d)*
CANADA							
Alberta and British Columbia	3,385	—	102	25,299	95,612	6,869	45,866
Southwest Saskatchewan	2,398	4,393	13,215	374	10,546	632	22,243
Southeast Saskatchewan	7,526	—	23,470	7,539	16,030	2,160	41,567
Total CANADA[(1)]	13,309	4,393	36,787	33,212	122,188	9,661	109,676
U.S.							
North Dakota and Montana	—	—	18,682	5,328	16,914	—	26,829
Total U.S.[(1)]	—	—	18,682	5,328	16,914	—	26,829
Total Corporate[(1)]	13,309	4,393	55,470	38,540	139,102	9,661	136,505

Note:

(1) Numbers may not add due to rounding.

In 2023, production in the Kaybob area of Alberta is estimated at 39,398 boe per day (comprised of 23,537 bbl/d NGLs; 95,166 Mcf/d Shale Gas). Condensate is estimated to make up 47% of 2023 total production from Kaybob. Production at Viewfield in southeast Saskatchewan is estimated at 29,739 boe per day (comprised of 3,661 bbl/d Light & Medium Oil; 17,893 bbl/d Tight Oil; 5,840 bbl/d NGL's; 13,174 Mcf/d Shale Gas; and 900 Mcf/d Conventional Natural Gas). Forecast production for the United States is all from North Dakota. The Kaybob, Viewfield and North Dakota areas make up 29%, 22% and 20% of the Corporation's Proved production estimate in the Crescent Point Reserve Report, respectively. Remaining areas each account for a small portion of the Corporation's production estimates for 2023.

The following table discloses, for each product type, the gross volume of production estimated by McDaniel for 2023 in the estimates of future net revenue with forecast pricing from Proved plus Probable reserves disclosed above under the heading "*Reserves Data – Forecast Prices and Costs*".

Region	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas	Total
	(bbls/d)	*(bbls/d)*	*(bbls/d)*	*(bbls/d)*	*(Mcf/d)*	*(Mcf/d)*	*(boe/d)*
CANADA							
Alberta and British Columbia	3,499	—	109	26,143	98,198	6,971	47,280
Southwest Saskatchewan	2,480	4,540	14,774	398	11,298	623	24,178
Southeast Saskatchewan	8,273	—	24,883	7,986	16,866	2,490	44,368
Total CANADA(1)	14,252	4,540	39,766	34,527	126,362	10,084	115,826
U.S.							
North Dakota and Montana	—	—	22,900	6,431	20,415	—	32,733
Total U.S.(1)	—	—	22,900	6,431	20,415	—	32,733
Total Corporate(1)	14,252	4,540	62,666	40,958	146,777	10,084	148,559

Note:

(1) Numbers may not add due to rounding.

In 2023, production in the Kaybob area of Alberta is estimated at 40,625 boe per day (comprised of 24,338 bbl/d NGLs; 97,722 Mcf/d Shale Gas). Condensate is estimated to make up 47% of 2023 total production from Kaybob. Production at Viewfield in southeast Saskatchewan is estimated at 31,570 boe per day (comprised of 4,137 bbl/d Light & Medium Oil; 18,810 bbl/d Tight Oil; 6,150 bbl/d NGL's; 13,754 Mcf/d Shale Gas; and 1,085 Mcf/d Conventional Natural Gas). Forecast production for the United States is all from North Dakota. The Kaybob, North Dakota and Viewfield areas make up 27%, 22% and 21% of the Corporation's Proved plus Probable production estimate in the Crescent Point Reserve Report, respectively. Remaining areas each account for a smaller portion of the Corporation's production estimates for 2023.

Production History

The following tables disclose, on a quarterly and annual basis for the year ended December 31, 2022, our share of average daily production volume (prior to deducting royalties), and the prices received, royalties, production costs and transportation costs incurred and netbacks received on a per unit of volume basis for each product type.

Average Daily Production Volume[(1)]

	Three Months Ended				Year Ended
	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Light and Medium Crude Oil (bbls/d)	15,365	15,752	12,347	13,671	14,274
Heavy Crude Oil (bbls/d)	4,034	4,103	4,102	3,870	4,027
Tight Oil (bbls/d)	43,932	42,553	42,030	40,068	42,134
NGLs (bbls/d)	29,947	30,322	33,668	33,871	31,967
Shale Gas (Mcf/d)	110,898	109,835	121,070	128,437	117,617
Conventional Natural Gas (Mcf/d)	10,045	10,800	10,307	10,769	10,482
Total (boe/d)	113,435	112,836	114,043	114,681	113,752
U.S.					
Light and Medium Crude Oil (bbls/d)	—	—	—	—	—
Heavy Crude Oil (bbls/d)	—	—	—	—	—
Tight Oil (bbls/d)	11,905	10,968	12,000	12,027	11,727
NGLs (bbls/d)	4,827	3,691	4,813	5,022	4,589
Shale Gas (Mcf/d)	15,724	10,089	12,979	14,366	13,285
Conventional Natural Gas (Mcf/d)	—	—	—	—	—
Total (boe/d)	19,353	16,341	18,976	19,443	18,530
TOTAL					
Light and Medium Crude Oil (bbls/d)	15,365	15,752	12,347	13,671	14,274
Heavy Crude Oil (bbls/d)	4,034	4,103	4,102	3,870	4,027
Tight Oil (bbls/d)	55,837	53,521	54,030	52,095	53,861
NGLs (bbls/d) [(2)]	34,774	34,013	38,481	38,893	36,556
Shale Gas (Mcf/d)	126,622	119,924	134,049	142,803	130,902
Conventional Natural Gas (Mcf/d)	10,045	10,800	10,307	10,769	10,482
Total (boe/d)	132,788	129,176	133,019	134,124	132,282

Notes:

(1) Numbers may not add due to rounding.

(2) For the year ended December 31, 2022, the Company's average condensate production was 19,518 bbl/s, which is included in NGLs production.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Light and Medium Crude Oil

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	104.07	131.32	116.88	102.99	114.10
Royalties	(15.47)	(20.66)	(23.80)	(18.06)	(19.34)
Production Costs[(1)]	(18.65)	(20.93)	(24.47)	(22.73)	(21.53)
Transportation Costs[(1)]	(2.03)	(2.30)	(2.10)	(1.75)	(2.05)
Netback Received	67.92	87.43	66.51	60.45	71.18
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs[(1)]	—	—	—	—	—
Transportation Costs[(1)]	—	—	—	—	—
Netback Received	—	—	—	—	—
TOTAL					
Prices Received	104.07	131.32	116.88	102.99	114.10
Royalties	(15.47)	(20.66)	(23.80)	(18.06)	(19.34)
Production Costs[(1)]	(18.65)	(20.93)	(24.47)	(22.73)	(21.53)
Transportation Costs[(1)]	(2.03)	(2.30)	(2.10)	(1.75)	(2.05)
Netback Received	67.92	87.43	66.51	60.45	71.18

Note:

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Heavy Crude Oil

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	101.03	122.53	95.50	77.38	99.34
Royalties	(25.77)	(32.31)	(25.15)	(19.76)	(25.82)
Production Costs(1)	(18.11)	(19.53)	(20.00)	(17.08)	(18.70)
Transportation Costs(1)	(2.31)	(2.36)	(2.23)	(2.34)	(2.31)
Netback Received	54.84	68.33	48.12	38.20	52.51
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs(1)	—	—	—	—	—
Transportation Costs(1)	—	—	—	—	—
Netback Received	—	—	—	—	—
TOTAL					
Prices Received	101.03	122.53	95.50	77.38	99.34
Royalties	(25.77)	(32.31)	(25.15)	(19.76)	(25.82)
Production Costs(1)	(18.11)	(19.53)	(20.00)	(17.08)	(18.70)
Transportation Costs(1)	(2.31)	(2.36)	(2.23)	(2.34)	(2.31)
Netback Received	54.84	68.33	48.12	38.20	52.51

Note:

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Tight Oil

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	114.57	134.86	108.60	99.85	114.65
Royalties	(11.23)	(13.78)	(10.78)	(9.95)	(11.45)
Production Costs(1)	(20.53)	(21.50)	(22.74)	(22.04)	(21.69)
Transportation Costs(1)	(4.82)	(4.40)	(5.39)	(5.67)	(5.06)
Netback Received	77.99	95.18	69.69	62.19	76.45
U.S.					
Prices Received	120.91	140.01	122.14	114.72	124.08
Royalties	(31.98)	(37.28)	(34.19)	(31.05)	(33.55)
Production Costs(1)	(17.91)	(17.39)	(16.15)	(13.95)	(16.31)
Transportation Costs(1)	(1.08)	(0.87)	(1.85)	(1.53)	(1.34)
Netback Received	69.94	84.47	69.95	68.19	72.88
TOTAL					
Prices Received	115.92	135.92	111.61	103.28	116.70
Royalties	(15.66)	(18.60)	(15.98)	(14.82)	(16.26)
Production Costs(1)	(19.98)	(20.65)	(21.28)	(20.17)	(20.52)
Transportation Costs(1)	(4.02)	(3.68)	(4.60)	(4.71)	(4.25)
Netback Received	76.26	92.99	69.75	63.58	75.67

Note:

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – NGLs

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	88.55	100.36	86.15	82.75	89.15
Royalties	(11.81)	(11.81)	(9.15)	(8.54)	(10.23)
Production Costs(1)	(9.06)	(10.58)	(9.66)	(10.47)	(9.96)
Transportation Costs(1)	(0.98)	(2.14)	(1.60)	(1.96)	(1.68)
Netback Received	66.70	75.83	65.74	61.78	67.28
U.S.					
Prices Received	52.07	54.89	45.90	36.69	46.16
Royalties	(10.07)	(9.43)	(8.85)	(6.37)	(8.60)
Production Costs(1)	(7.20)	(6.89)	(6.06)	(4.33)	(6.05)
Transportation Costs(1)	(2.90)	(0.86)	(0.34)	(0.39)	(1.12)
Netback Received	31.90	37.71	30.65	25.60	30.39
TOTAL					
Prices Received	83.49	96.42	82.79	78.40	83.76
Royalties	(11.57)	(11.55)	(9.11)	(8.26)	(10.02)
Production Costs(1)	(8.80)	(10.18)	(9.21)	(9.68)	(9.47)
Transportation Costs(1)	(1.25)	(2.00)	(1.44)	(1.76)	(1.61)
Netback Received	61.87	72.69	63.03	58.70	62.66

Note:

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Shale Gas

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	5.52	8.05	6.17	6.39	6.52
Royalties[2]	0.02	(0.40)	(0.02)	0.07	(0.08)
Production Costs[1]	(0.67)	(0.93)	(0.80)	(0.92)	(0.83)
Transportation Costs[1]	(0.41)	(0.42)	(0.38)	(0.46)	(0.42)
Netback Received	4.46	6.30	4.97	5.08	5.19
U.S.					
Prices Received	6.07	8.67	10.32	6.61	7.75
Royalties	(1.13)	(1.78)	(2.23)	(1.19)	(1.54)
Production Costs[1]	(0.84)	(1.10)	(1.38)	(0.80)	(1.01)
Transportation Costs[1]	(0.27)	(0.24)	(0.21)	(0.25)	(0.24)
Netback Received	3.83	5.55	6.50	4.37	4.96
TOTAL					
Prices Received	5.59	8.11	6.57	6.42	6.64
Royalties[2]	(0.12)	(0.52)	(0.23)	(0.06)	(0.23)
Production Costs[1]	(0.69)	(0.94)	(0.85)	(0.91)	(0.85)
Transportation Costs[1]	(0.39)	(0.41)	(0.36)	(0.44)	(0.40)
Netback Received	4.39	6.24	5.13	5.01	5.16

Notes:

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

(2) In Canada, royalties include the impact of the gas cost allowance.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Conventional Natural Gas

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	5.09	7.09	6.29	5.80	6.08
Royalties[(2)]	0.72	0.92	0.27	0.18	0.52
Production Costs[(1)]	(0.62)	(0.82)	(0.81)	(0.84)	(0.77)
Transportation Costs[(1)]	(0.43)	(0.40)	(0.24)	(0.39)	(0.36)
Netback Received	4.76	6.79	5.51	4.75	5.47
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs[(1)]	—	—	—	—	—
Transportation Costs[(1)]	—	—	—	—	—
Netback Received	—	—	—	—	—
TOTAL					
Prices Received	5.09	7.09	6.29	5.80	6.08
Royalties[(2)]	0.72	0.92	0.27	0.18	0.52
Production Costs[(1)]	(0.62)	(0.82)	(0.81)	(0.84)	(0.77)
Transportation Costs[(1)]	(0.43)	(0.40)	(0.24)	(0.39)	(0.36)
Netback Received	4.76	6.79	5.51	4.75	5.47

Notes:

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

(2) In Canada, royalties include the impact of the gas cost allowance.

Production Volume by Field

The following table discloses for each important field, and in total, our production volumes for the year ended December 31, 2022 for each product type.

Region	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas	Total
	(bbls/d)	*(bbls/d)*	*(bbls/d)*	*(bbls/d)*	*(Mcf/d)*	*(Mcf/d)*	*(boe/d)*
CANADA							
Viewfield	3,943	—	18,697	5,787	12,066	1,133	30,627
Flat Lake	4,180	—	6,572	1,807	2,499	1,444	13,216
Shaunavon	2,376	—	14,029	368	10,798	369	18,634
Kaybob Duvernay	—	—	13	21,882	89,808	23	36,867
Other Canada [(2)]	3,775	4,027	2,823	2,123	2,446	7,513	14,408
Total CANADA[(1)]	14,274	4,027	42,134	31,967	117,617	10,482	113,752
U.S.							
North Dakota	—	—	11,727	4,589	13,285	—	18,530
Total U.S.[(1)]	—	—	11,727	4,589	13,285	—	18,530
Total[(1)]	14,274	4,027	53,861	36,556	130,902	10,482	132,282

Notes:

(1) Numbers may not add due to rounding.

(2) Includes all remaining assets in Canada.

ADDITIONAL INFORMATION RESPECTING CRESCENT POINT

Directors and Officers

Crescent Point has a board of directors currently consisting of ten individuals. The directors are elected by Shareholders and hold office until the next annual meeting of the Corporation.

The name, municipality of residence and principal occupation during the last five years of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held with the Corporation	Date First Elected or Appointed as Director
Craig Bryksa [4] Calgary, Alberta	President, Chief Executive Officer and Director	2018
Kenneth R. Lamont Calgary, Alberta	Chief Financial Officer	Not applicable
Ryan Gritzfeldt Calgary, Alberta	Chief Operating Officer	Not applicable
Mark G. Eade Calgary, Alberta	Senior Vice President, General Counsel and Corporate Secretary	Not applicable
Garret Holt Calgary, Alberta	Senior Vice President, Corporate Development	Not applicable
Michael Politeski [7] Calgary, Alberta	Senior Vice President, Finance and Treasurer	Not applicable
Shelly Witwer [7] Calgary, Alberta	Senior Vice President, Business Development	Not applicable
Justin Foraie [7] Calgary, Alberta	Vice President, Engineering and Marketing	Not applicable
Barbara Munroe [6] Calgary, Alberta	Director and Chair of the Board	2016
James E. Craddock[2] [3] [5] Whitney, Texas	Director	2019
John P. Dielwart [3] [4] Calgary, Alberta	Director	2019
Ted Goldthorpe [1] [5] New York, New York	Director	2017
Mike Jackson [1] [5] Calgary, Alberta	Director	2016
Jennifer F. Koury [2] [5] Calgary, Alberta	Director	2019
Francois Langlois [1] [3] [4] Calgary, Alberta	Director	2018
Myron M. Stadnyk [2] [3] [4] Calgary, Alberta	Director	2020
Mindy Wight [1] [2] Prince George, British Columbia	Director	2022

Notes:

(1) Member of the Audit Committee.

(2) Member of the Human Resources and Compensation Committee.

(3) Member of the Reserves Committee.

(4) Member of the Environmental, Safety and Sustainability Committee.

(5) Member of Corporate Governance and Nominating Committee.

(6) Chair of the Board serves in an *ex officio* capacity on each Committee.

(7) Michael Politeski and Shelly Witwer were promoted to Senior Vice President and Justin Foraie was promoted to an Officer of the Corporation, effective January 1, 2023.

As at February 20, 2023, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 2,419,373 Common Shares, representing approximately 0.4% of the issued and outstanding Common Shares. Including restricted shares and options, ownership increased to 1.1% on a fully diluted basis.

Craig Bryksa, President, Chief Executive Officer and Director

Craig Bryksa is the President, Chief Executive Officer and a Director of Crescent Point, roles he has held since September 2018. Prior to his current position, Mr. Bryksa was Vice President, Engineering West and has held a number of senior management roles with Crescent Point since joining the Corporation in 2006, directly overseeing the development and operations of each of Crescent Point's core assets.

Mr. Bryksa is the Chair of the Board of Governors at the Canadian Association of Petroleum Producers ("**CAPP**"). He has significant experience as a professional engineer in the oil and gas industry, working with companies such as Enerplus Resources Fund and McDaniel & Associates Consultants. Mr. Bryksa is a member of the Association of Professional Engineers and Geoscientists of Alberta ("**APEGA**") and Association of Professional Engineers and Geoscientists of Saskatchewan ("**APEGS**"). He holds a Bachelor of Applied Science degree in petroleum engineering from the University of Regina.

Ken Lamont, Chief Financial Officer

Ken Lamont is the Chief Financial Officer of Crescent Point, a role he has held since January 2016. Prior to that, he was Vice President, Finance and Treasurer for Crescent Point. Mr. Lamont has worked in the oil and gas industry since 2001, having held a variety of roles with companies such as Shelter Bay Energy Inc., Direct Energy Marketing Ltd. and Shell Trading Gas and Power Canada Ltd. Prior to 2001, he was a Senior Manager at PricewaterhouseCoopers LLP.

Mr. Lamont holds a Bachelor of Commerce degree (with distinction) from the University of Alberta, is a Chartered Professional Accountant and holds the ICD.D designation. He is a member of the Chartered Professional Accountants of Alberta and a member of the Institute of Corporate Directors.

Ryan Gritzfeldt, Chief Operating Officer

Ryan Gritzfeldt is the Chief Operating Officer of Crescent Point, a role he has held since 2018. Prior to that, he was Vice President, Marketing and Innovation and Vice President, Engineering and Business Development East for Crescent Point from 2010 until 2018. Additionally, he was Engineering Manager, Southeast Saskatchewan from 2006 until 2009. Mr. Gritzfeldt has worked in the oil and gas industry since 1998, having held a variety of roles with companies such as Shelter Bay Energy Inc. and Talisman Energy Inc. in addition to Crescent Point.

Mr. Gritzfeldt is a member of APEGA and APEGS. He holds a Bachelor of Applied Science degree (with great distinction) in industrial systems engineering from the University of Regina.

Mark Eade, Senior Vice President, General Counsel and Corporate Secretary

Mark Eade is the Senior Vice President, General Counsel and Corporate Secretary at Crescent Point. Mr. Eade has served as Corporate Secretary since 2004 and was formerly Vice President, General Counsel and Corporate Secretary. Prior to being named Vice President at Crescent Point in September 2015, he was a partner with Norton Rose Fulbright Canada LLP from August 2011 to August 2015. Prior thereto, Mr. Eade was a partner at McCarthy Tétrault LLP. Mr. Eade has over 25 years of experience in corporate governance, securities and mergers and acquisitions law and has represented clients in a number of significant acquisitions and public offerings.

Mr. Eade holds a Bachelor of Commerce degree (with honors) and a LL.B. degree from the University of Saskatchewan and was called to the Alberta bar in 1994. He is a member of the Law Society of Alberta and the Canadian Bar Association.

Garret Holt, Senior Vice President, Corporate Development

Garret Holt is Crescent Point's Senior Vice President, Corporate Development, a role he assumed in 2019. Mr. Holt has over 30 years of experience in the oil and gas industry. Most recently, he was an Executive Director in Energy Investment Banking with JPMorgan. Prior to that, Mr. Holt held senior executive positions with Wapiti Energy, LLC as Chief Operating Officer and Fairways E&P, LLC as Senior Vice President of Exploration and Production.

He graduated from the University of Tulsa with a Bachelor of Science, Petroleum Engineering (Magna Cum Laude) and is a Registered Professional Engineer.

Michael Politeski, Senior Vice President, Finance and Treasurer

Michael Politeski is the Senior Vice President, Finance and Treasurer. He has held an executive role with the Corporation since joining Crescent Point in March 2015. Mr. Politeski has worked in the oil and gas industry since 2003 in various areas, including treasury and debt capital markets, tax, risk management and insurance, corporate reporting, operational accounting and supply chain management. Prior to joining Crescent Point, Mr. Politeski was the Treasurer and Corporate Controller of Enerplus Corporation and held various management roles with Halliburton Canada and KPMG LLP.

Mr. Politeski is a Chartered Professional Accountant and holds a Bachelor of Commerce degree (with distinction) from the University of Saskatchewan. He is a member of the Institute of Chartered Professional Accountants of Alberta.

Shelly Witwer, Senior Vice President, Business Development

Shelly Witwer is Crescent Point's Senior Vice President, Business Development. Since joining the Corporation in 2007, she has held a number of senior management roles, including Vice President, Land and Vice President, Business Development. Ms. Witwer has significant experience in land and business development roles, having worked with companies such as BP Energy, Burlington Resources and Bear Ridge Resources.

Ms. Witwer is a member of the Canadian Association of Petroleum Landmen and the Petroleum Acquisition and Divestment Association. She holds a Bachelor of Commerce degree and a Bachelor of Arts degree in Energy Economics from the University of Calgary.

Justin Foraie, Vice President, Engineering and Marketing

Justin Foraie is Crescent Point's Vice President, Engineering and Marketing. Mr. Foraie has been with the Corporation since 2009 and has held engineering roles of increasing responsibility, primarily focused on developing the Corporation's United States properties, where he previously served as Vice President, U.S. Operations for CPEUS. Prior to joining Crescent Point, Mr. Foraie worked for Talisman Energy, Inc..

Mr. Foraie has a Bachelor of Applied Science degree in Petroleum Systems Engineering from the University of Regina and is a graduate of the Stanford Graduate School of Business LEAD program. Mr. Foraie became a Registered Professional Engineer in 2008 and is a member of APEGA and Saskatchewan APEGS.

Barbara Munroe, Chair of the Board

Ms. Barbara Munroe was admitted to the Law Society of Alberta in 1991 and brings over 30 years of legal experience and industry diversification to the Board. Prior to retiring in March 2019, Ms. Munroe served as Executive Vice President, Corporate Services and General Counsel for WestJet Airlines, a position she held since November 2016. Ms. Munroe joined WestJet in November 2011 as Vice President & General Counsel and was promoted to Senior Vice President, Corporate Services & General Counsel in June 2015. She was the Assistant General Counsel, Upstream at Imperial Oil Ltd. from 2008 to 2011 and the Senior Vice President, Legal/IP & General Counsel, Corporate Secretary for SMART Technologies Inc. from 2000 to 2008. Ms. Munroe additionally serves as a Director of ENMAX Corporation and Willow Biosciences Inc., as well as a trustee of the Alberta Cancer Foundation.

Ms. Munroe holds the ICD.D designation and is a member of the Institute of Corporate Directors. She holds a Bachelor of Commerce, Finance degree and a Bachelor of Law degree, both from the University of Calgary. As Chair of the Board, Ms. Munroe serves on each committee in an *ex officio* capacity.

James E. Craddock, Director

Mr. James E. Craddock is a seasoned upstream executive who possesses broad-based technical knowledge with over 30 years of experience. He served on Noble Energy Inc.'s Board of Directors since its merger with Rosetta Resources Inc. from 2015 to 2020 and served as the Chairman, Chief Executive Officer and President of Rosetta from 2013 to 2015. Previously, he was the Executive Director and Chief Operating Officer for BPI Industries Inc. and held several positions of increasing responsibility over a 20-year career at Burlington Resources Inc.

Mr. Craddock holds a Bachelor of Science in Mechanical Engineering from Texas A&M University and previously served on the Boards of Templar Energy and the Texas Railroad Commission's Eagle Ford Task Force.

John P. Dielwart, Director

Mr. John P. Dielwart brings a wealth of experience and knowledge to Crescent Point's Board, developed through his varied 40-year career in the oil and gas sector. Most notably, Mr. Dielwart is a founding member of ARC Resources Ltd., holding the position of Chief Executive Officer from 2001 to 2013. He is also a Partner in ARC Financial Corp., sitting on its Investment and Governance committees where he provides leadership support on various complex issues, including internal governance and investment decision-making. Mr. Dielwart is also Chairman of the Board of TransAlta Corporation. Prior to joining ARC in 1996, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as Senior Vice-President and a Director, where he gained extensive technical knowledge of oil and natural gas properties in Western Canada.

Mr. Dielwart has a Bachelor of Science in Civil Engineering with Distinction from the University of Calgary. He is a professional engineer, holds the ICD.D designation granted by the Institute of Corporate Directors and has served two three-year terms as a Governor of CAPP, including 18 months as Chair.

Ted Goldthorpe, Director

Mr. Ted Goldthorpe is a financial professional who has been serving as Partner in charge of Global Credit Business for BC Partners since February 2017. Prior thereto, he was the President of Apollo Investment Corporation, Chief Investment Officer of Apollo Investment Management, and Senior Portfolio Manager, U.S. Opportunistic Credit from April 2012 to August 2016. Previously, Mr. Goldthorpe was employed by Goldman Sachs & Co., where he held a variety of positions after joining the firm in 1999. Mr. Goldthorpe serves as the

CEO and Board Chair of Mount Logan Capital Inc., Portman Ridge Finance Corporation and Logan Ridge Financial Corporation and serves as President and CEO and Chair of Board of trustees of the Alternative Credit Income Fund and Opportunistic Credit Interval Fund. In January 2021, Mr. Goldthorpe was appointed to the Board of KITS Eyewear and also serves as Lead Director.

Mr. Goldthorpe received a Bachelor of Arts in Commerce from Queen's University and is a frequent guest lecturer at leading universities across North America. Mr. Goldthorpe currently serves on the Global Advisory Board for the Queen's School of Business, is on the Board of the Canadian Olympic Foundation, and serves on the Board of Directors for Her Justice and Capitalize for Kids.

Mike Jackson, Director

Mr. Mike Jackson worked in the banking industry from 1984 to 2016 and brings more than 30 years of financial experience in corporate and investment banking. Most recently, he was Managing Director - Investment Banking, Scotiabank Global Banking and Markets, with a focus on the oil and gas industry from 2008 until his retirement in 2016. Prior to that, Mr. Jackson held several senior management roles at Scotiabank, including Managing Director, Oil & Gas Industry Head & Calgary Office Head from 1999 to 2007 and Vice President & Office Head, Corporate Banking Calgary from 1997 to 1999.

Mr. Jackson holds a Bachelor of Science degree and a Master of Business Administration, both from Dalhousie University. Additionally, Mr. Jackson completed the Executive Management Program at Queen's University and holds the ICD.D designation granted by the Institute of Corporate Directors.

Jennifer F. Koury, Director

Ms. Jennifer F. Koury has over 35 years of professional experience, holding various senior executive positions with BHP Biliton from 2011 to 2017. Part of her responsibilities included the development of BHP Billiton's total rewards program for executives and employees of the Petroleum World-Wide Business. Prior to that, she was Vice President of Corporate Services for Enerplus Corp. from 2006 to 2011 and also held senior management positions with Imperial Oil/Exxon Mobil.

Ms. Koury serves as the Vice-Chair of the Board for the Calgary Zoo, Director for Board Ready Women and Director for Bird Construction. She holds a Bachelor of Commerce degree from the University of Alberta and the ICD.D designation granted by the Institute of Corporate Directors.

François Langlois, Director

Mr. Langlois is an oil and gas executive who brings over 35 years of domestic and international experience to the Crescent Point Board, most recently from his role as Senior Vice President, Exploration & Production with Suncor Energy Inc., where he was responsible for the financial and operating performance of the group from 2011 until his retirement in 2016. Prior thereto, he was Vice President, Unconventional Gas from 2009 to 2010 and held various roles with Petro-Canada from 1982 to 2009, most recently as Vice President, Western Canada Production & North American Exploration.

Mr. Langlois holds a Bachelor Geological Engineering from Laval University (Quebec City) and the ICD.D designation granted by the Institute of Corporate Directors.

Myron M. Stadnyk, Director

Mr. Myron M. Stadnyk has over 35 years of oil and gas experience and is the former President and CEO of ARC Resources Ltd., retiring in 2020. Mr. Stadnyk was the first operations employee at ARC, after the Corporation's initial public offering, to progress to COO (2005), President (2009) and CEO (2013). Prior to ARC, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations.

Mr. Stadnyk holds a Bachelor of Science in Mechanical Engineering from the University of Saskatchewan and is a graduate of the Harvard Business School Advanced Management Program and holds an ICD.D designation from the Institute of Corporate Directors. He is a member of APEGA and served as a Governor for CAPP for over 10 years. He also holds Board positions for Prairie Sky Royalty Ltd. and Vermilion Energy, Inc..

Mindy Wight, Director

Ms. Mindy Wight brings over 15 years of tax and financial expertise from her current role of Chief Executive Officer for the Nch'kay Development Corporation. She previously held the role of Chief Financial Officer, as well as holding the role as Treasurer of the Board of Directors.

Prior to joining Nch'kay Development Corporation in November 2021, Ms. Wight held progressive tax roles at MNP LLP from 2016 to 2021 and most recently was a partner and National Leader of Indigenous Tax Services for the firm. Ms. Wight has also worked for two of the Big Four National accounting firms, the Chartered Accounting School of Business and the Canada Revenue Agency since graduating from the University of Northern British Columbia with a Bachelor of Commerce Degree, Accounting in 2007. Ms. Wight also possesses Chartered Professional Accountant, Chartered Accountant, and Certified Aboriginal Financial Manager designations.

Ms. Wight has historically held Board positions as the Chair of the Board of Directors and Chair of the Finance and Audit Committee for the Nch'kay Development Corporation and was an Advisory Committee Member of the Budget and Financial Committee to the Squamish Nation.

Bankruptcies and Cease Trade Orders

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation is, as of the date of this AIF, or has been, within the last 10 years, been a director or executive officer of any company (including the Corporation) that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the Corporation access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of that person, except for Mr. Dielwart, who was a director of Denbury Resources Inc. ("**Denbury**") when it entered into Chapter 11 proceedings in the United States on July 30, 2020. Denbury subsequently emerged from Chapter 11 proceedings on September 18, 2020 and Mr. Dielwart resigned as a director of Denbury at that time.

Penalties or Sanctions

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the 10 years preceding the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares.

Common Shares

Each Common Share entitles its holder to receive notice of and to attend all meetings of the Shareholders of the Corporation and to one vote at such meetings. The holders of Common Shares are, at the discretion of the Board of Directors and subject to applicable legal restrictions, entitled to receive any dividends declared by the Board of

Directors. The holders of Common Shares are entitled to share equally in any distribution of the assets of the Corporation upon the liquidation, dissolution, bankruptcy or winding up of the Corporation or other distribution of its assets among its Shareholders for the purpose of winding up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to any other shares having priority over the Common Shares.

Premium Dividend™ and Dividend Reinvestment Plan

The DRIP was in effect from 2010 until August 2015, when it was suspended.

Under the Corporation's DRIP, eligible Shareholders may, at their option, reinvest their cash dividends to purchase additional Common Shares at 95% of the average market price (as defined in the DRIP) of a Common Share on the applicable distribution date. The DRIP also provides an alternative where eligible Shareholders may elect, under the premium dividend component, to receive a premium cash distribution equal to 102% of the reinvested cash dividends that such Shareholders would have otherwise been entitled to receive on the applicable dividend date. Generally, no commissions, service charges or brokerage fees will be payable by Shareholders who participate in the DRIP. We have reserved the right to determine how much new equity is available under the Plan on any particular distribution date. Accordingly, participation in the DRIP may be pro-rated in certain circumstances.

Registered and beneficial owners of Common Shares who are not resident in Canada are not eligible to participate in the DRIP.

Share Dividend Plan

The SDP was in effect from May 9, 2014 until it was suspended on August 12, 2015.

Under the terms of the SDP, eligible Shareholders may, at their option, elect to receive dividends declared on Common Shares as share dividends rather than cash dividends, where such share dividends are declared by the Board of Directors, to be payable in either cash or Common Shares at the election of the Shareholder. Share dividends are satisfied through the issuance of new Common Shares equal to the amount obtained by dividing the dollar amount of the dividend per Common Share by 95% of the average market price (as defined in the SDP) on the TSX. Generally, no commissions, service charges or brokerage fees will be payable by Shareholders who participate in the SDP. Under the SDP, we have reserved the right to determine how much new equity is available under the SDP on any particular distribution date. Accordingly, participation in the SDP may be pro-rated in certain circumstances.

Unlike the dividend reinvestment component of the DRIP, which gives only Shareholders resident in Canada the option to reinvest cash dividends into Common Shares at a 5% discount to market prices, the SDP provides all Shareholders with the option to receive dividends in the form of Common Shares at a 5% discount to current market prices.

Restricted Share Bonus Plan

Under the terms of the Corporation's Restricted Share Bonus Plan, any director, officer or employee of the Corporation who, in each case, in the opinion of the Board of Directors, hold an appropriate position with the Corporation to warrant participation in the Restricted Share Bonus Plan (collectively, the "**RSBP Participants**") may be granted restricted shares ("**Restricted Shares**") which vest over time and, upon vesting, can be redeemed by the holder for cash or Common Shares at the option of the Corporation. The Restricted Share Bonus Plan is administered by the Board of Directors. Under the Restricted Share Bonus Plan at December 31, 2022 the Corporation is authorized to issue up to 11,210,550 Common Shares, of which the Corporation had 2,244,738 Restricted Shares outstanding at December 31, 2022.

The Restricted Shares vest on terms up to three years from the grant date as determined by the Board of Directors. Upon redemption, the Corporation will be required to pay to the RSBP Participant the fair market value of the redeemed Restricted Shares, based on the weighted average of the prices at which the Common Shares traded on the TSX for the five trading days immediately preceding the redemption date, plus any accrued but unpaid dividend amounts in respect of such Restricted Shares (the "**Payout Amount**"). The Payout Amount may be satisfied by the Corporation making a cash payment, the Corporation purchasing Common Shares in the market and delivering such Common Shares to the RSBP Participant or by issuing Common Shares from treasury.

DSU Plan

In 2012, the Corporation established a deferred share unit plan (the "**DSU Plan**") to enhance its ability to attract and retain key personnel (namely, selected officers and employees and non-employee directors) and reward significant performance achievements. Under the terms of the DSU Plan, Designated Employees and Directors (as defined in the DSU Plan), who, in the opinion of the Board of Directors, warrant participation in the DSU Plan (the "**Participants**"), may be granted deferred share units ("**Units**"). As at the date hereof, only non-employee directors have been granted DSUs.

Participants that are directors must elect to receive Units in lieu of a cash retainer prior to the year in which the retainer will be earned, unless they are elected or appointed part way through a year, in which case they must elect within 30 days of being elected or appointed to receive Units for that year. Participants that are Designated Employees must elect to receive Units in lieu of all or a portion of their annual bonus entitlement or profit share for the year within 30 days after such Designated Employee has been notified by the Corporation of such individual's bonus entitlement or profit share for such year.

The Corporation establishes an account for each Participant and all Units are credited to the applicable account as of the award date. The number of Units to be credited to an account is determined by dividing the dollar amount elected by the Participant by the five day weighted average closing price of the Common Shares on the TSX immediately prior to the award date. On the last day of each fiscal quarter of the Corporation or as soon as possible thereafter, the Corporation determines whether any dividend has been paid on Common Shares during such fiscal quarter and, if so, the rate thereof per Common Share (the "**Dividend Rate**") and, within 10 business days of the applicable fiscal month end, the Corporation credits each applicable account with an additional number of Units equal to (i) the number of Units in the applicable account on the record date for such dividend multiplied by (ii) the Dividend Rate. All Units vest immediately upon being credited to a Participant's account.

A Participant is not entitled to any payment of any amount in respect of Units until such Participant ceases to be an employee or director of the Corporation, as the case may be, for any reason whatsoever. Upon the Participant ceasing to be an employee or director of the Corporation, the Participant is entitled to receive a lump sum cash payment, net of applicable withholding taxes, equal to the product of (i) the number of Units in such Participant's account on the date the Participant ceased to be an employee or director and (ii) the five day weighted average closing price of the Common Shares on the TSX immediately prior to such date, unless the redemption event occurs during a black out period, in which case the amount of such payment will be calculated with reference to the five day weighted average closing price of the Common Shares on the TSX on the fifth business day following the end of such black out period. The Corporation will make such lump sum cash payment by the end of the calendar year following the year in which the Participant ceased to be an employee or director.

On March 10, 2015, the Board amended the DSU Plan to include provisions that govern citizens and residents in conformity with Section 409A of the U.S. Internal Revenue Code. This amendment was made to clarify and explicitly disclose certain tax consequences associated with participation in the DSU Plan by eligible U.S. citizens and U.S. residents.

PSU Plan

In 2017, the Corporation adopted the PSU Plan, which is administered by the Board of Directors. The purposes of the PSU Plan are: (i) to promote alignment of interests between participants in the PSU Plan and Shareholders by providing the participants with an opportunity to participate in an increase in the equity value of the Corporation, taking into account the performance of the Corporation relative to its peers and targets established by the Board; (ii) to provide participants in the PSU Plan with compensation reflective of their responsibility, commitment and risk accompanying their role over the long-term; and (iii) to provide a retention incentive to participants in the PSU

Plan over the long-term. Under the terms of the PSU Plan, the Compensation Committee may designate employees of the Corporation or its affiliates who are eligible to receive performance share units ("**PSUs**"). PSUs are notional grants of share-based compensation units that entitle the holder to a cash payment upon redemption of the PSU.

Unlike Restricted Shares, PSUs do not automatically vest over time. Instead, vesting is dependent on the achievement of various corporate performance metrics over a three year performance period.

The vested number of PSUs relating to a given performance period are paid out in cash based on the volume weighted average trading price of the Common Shares on the TSX over the five business days subsequent to the end of the performance period for the applicable PSUs, plus the dividends paid during the applicable performance period.

Based on underlying units prior to any effect of the performance multiplier, the Corporation had 2,713,176 PSUs outstanding at December 31, 2022.

Stock Option Plan

The Corporation adopted the Stock Option Plan in early 2018, with the purpose of rewarding those persons who promote the growth and success of the Corporation and assisting the Corporation in attracting, motivating and retaining personnel. The Stock Option Plan was approved by the Shareholders at the Corporation's annual meeting of shareholders on May 4, 2018 and amended to reduce the maximum number of Common Shares issuable under the Stock Option Plan at the Corporation's annual meeting of shareholders on May 14, 2020. The Corporation has made no stock option ("**Options**") grants in 2022 and does not intend to grant any further Options.

Pursuant to the terms of the Stock Option Plan, a maximum of 10,000,000 Common Shares may be issuable upon the exercise of Options granted under the Stock Option Plan (subject to adjustment for any subdivision or consolidation of the Common Shares). As at December 31, 2022, there were 3,889,130 Options to purchase Common Shares outstanding. Additionally, the number of Common Shares issuable to insiders of the Corporation (as defined in the Company Manual of the TSX) in any one year period, or at any time when combined with Common Shares issued or issuable under any of the Corporation's other security-based compensation plans, may not exceed 10% of the issued and outstanding Common Shares, and no one insider (or associates of that insider, as defined in the Company Manual of the TSX) may be issued more than 5% of the issued and outstanding Common Shares in any one year period. Non-employee directors are not entitled to participate in the Stock Option Plan. No Options shall be granted to any participant if the total number of Common Shares issuable to or on behalf of such participant under the Stock Option Plan, together with any Common Shares reserved for issuance to such participant under any other share compensation or incentive mechanism of the Corporation (which includes RSUs issued under the Restricted Share Bonus Plan) would exceed 5% of the aggregate issued and outstanding Common Shares.

The Board of Directors administer the Stock Option Plan, and will from time to time designate officers and employees of the Corporation who are entitled to participate in the Stock Option Plan, and determine the number and exercise price of Options to be granted to such participants. Non-employee directors are prohibited from participating in the Stock Option Plan. Under the Stock Option Plan, the exercise price of Options is determined by the Board of Directors at the time of grant, but will not be less than permitted by the applicable rules and policies of the TSX. Subject to the vesting provisions of the Stock Option Plan, Options may be: (i) exercised by paying the Corporation the exercise price in exchange for Common Shares; (ii) surrendered to the Corporation in exchange for a cash payment representing the aggregate difference between the market price of the Common Shares and the exercise price of the Options surrendered; or (iii) surrendered to the Corporation in exchange for a number of Common Shares equivalent in value (based on the market price) to the aggregate difference between market price of the Common Shares and the exercise price of the Options surrendered.

Unless the Board of Directors determine otherwise, Options granted pursuant to the Stock Option Plan will have a term of seven years, subject to early expiry in accordance with the change in control and other provisions of the Stock Option Plan. All Options are granted pursuant to stock option agreements executed at the time of grant by the Corporation and the grantee.

Employee Share Value Plan

In early 2020, the Corporation adopted an Employee Share Value Plan ("**ESVP**") for certain employees in lieu of grants that would have previously been made under the Restricted Share Bonus Plan. Under the terms of the ESVP, any employee of the Corporation who, in each case, in the opinion of the Board of Directors, holds an appropriate position with the Corporation to warrant participation in the ESVP (collectively, the "**ESVP Participants**") may be granted rights ("**Awards**") which vest over time and, upon vesting, entitle the participant to receive a cash payment for each Award equal to the five day weighted average trading price on the TSX of the Common Shares immediately preceding the vesting date plus an amount equal to the aggregate amount paid by the Corporation in dividends per Common Share from the grant date of an Award to and including the vesting date (collectively, the "**Payout Value**"). ESVP Participants do not have any right to receive Common Shares in respect of vested Awards.

Awards vest as to 33 1/3% on each of the first, second and third anniversaries of the grant date as determined by the Board of Directors. Upon vesting of an Award, the Corporation is required to pay to an ESVP Participant the Payout Value within 15 business days of vesting and, in all cases, prior to December 31 of the year of vesting.

The Employee Share Value Plan is administered by the Board of Directors. At December 31, 2022, there were 5,274,478 awards outstanding.

Long-Term Debt

At December 31, 2022, the Corporation had a $2.26 billion syndicated unsecured credit facility (the "**Syndicated Credit Facility**") and a $100 million unsecured operating credit facility with one Canadian chartered bank (the "**Bi-Lateral Credit Facility**"). The Syndicated Credit Facility is with eleven banks and has a maturity date of November 26, 2026. The current maturity date of the Bi-Lateral Credit Facility is November 26, 2026. The Syndicated Credit Facility's interest rate is based on either Canadian prime rate, U.S. base rate, Secured Overnight Financing Rate or bankers' acceptance rates at the Corporation's option subject to certain basis point or stamping fee adjustments ranging from 0.25% to 3.15% depending on the Corporation's senior debt to earnings before interest, taxes, depreciation and amortization, adjusted for certain non-cash items ("**adjusted EBITDA**") ratio. The Credit Facilities are guaranteed by certain restricted subsidiaries currently being CPEUS, CPUSH, CPHL and the Partnership. Various borrowing options are available under the Credit Facilities, including Canadian prime rate-based advances, U.S. base rate-based advances, Secured Overnight Financing Rate loans and bankers' acceptance loans. The Bi-Lateral Credit Facility and Syndicated Credit Facility constitute revolving credit facilities and are extendible annually. The Credit Facilities contain standard commercial covenants for facilities of this nature. Distributions to Shareholders and share repurchases are not permitted if the Corporation is in default of the Credit Facilities or if the making of such distribution would cause an event of default. The Corporation does not have a borrowing base restriction respecting its Credit Facilities. At December 31, 2022, the Corporation was undrawn on its bank credit facilities.

At December 31, 2022, the Corporation had approximately $1.4 billion of senior guaranteed notes ("the Senior Guaranteed Notes") outstanding of which $538.7 million become due within one year excluding the value of underlying cross currency swaps. The Senior Guaranteed Notes are unsecured and rank pari passu with the Corporation's credit facilities and carry a bullet repayment on maturity. The Senior Guaranteed Notes have financial covenants similar to those of the credit facilities described above. Concurrent with the issuance of US$921.0 million Senior Guaranteed Notes, the Corporation entered into cross currency swaps to hedge its foreign exchange exposure, fixing a notional amount of $1.05 billion for the purpose of interest and principal repayments.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas entities of similar size. All current legislation is a matter of public record, and we are unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing - Oil

In Canada and the United States, producers of oil negotiate sales contracts directly with oil purchasers. Oil prices are primarily based on worldwide and North American supply and demand. The specific price paid depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance.

Oil exports from Canada may be made pursuant to an export contract with a term not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the Canada Energy Regulator (the "**CER**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the CER and the issue of such a license requires the approval of the Governor in Council.

In the United States, transportation of crude oil is subject to rate and access regulation. The Federal Energy Regulatory Commission (the "**FERC**") regulates interstate crude oil pipeline transportation rates under the *Interstate Commerce Act* of 1887 (the "**ICA**"). In general, such pipeline rates must be cost-based. The FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service. Such rates and terms and conditions may not be discriminatory or preferential. At the beginning of 1995, regulations adopted by the FERC generally grandfathered all previously approved interstate transportation rates and established an indexing system for such rates permitting annual adjustments based on the rate of inflation, subject to certain limitations. Every five years, the FERC examines the annual change compared to the actual cost changes. In December 2015, under the five-year re-determination, the FERC adjusted the index level used to determine annual changes to oil pipeline rate ceilings and determined that the Producer Price Index for Finished Goods ("**PPI-FG**") plus 1.23% should be the index level for the five-year period beginning July 1, 2016. In December 2020, the FERC adjusted the index level to be the PPI-FG plus 0.78% for the July 1, 2021 to June 30, 2026 time period. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Intrastate crude oil pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state.

On December 18, 2015, the U.S. Congress passed, and the President signed, legislation into law which repealed the 40-year old ban on exports of crude oil produced in the United States. Accordingly, most exports of domestically-produced crude oil may be made without an export license. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas sold intra-provincially or to the United States is determined by negotiation between buyers and sellers. In the United States, the price of inter-state or international sales is determined by negotiation between buyers and sellers based upon factors normally considered in the industry such as distance from well to pipeline, pressure, and quality. Natural gas exported from Canada is subject to regulation by the CER and the Government of Canada, and in the United States is regulated principally by the FERC and the United States Department of Energy (the "**DOE**"). The FERC, which has the authority under the *Natural Gas Act* of 1938 (the "**NGA**") to regulate prices, terms and conditions for the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to FERC regulation, except interstate pipelines, to resell natural gas at market prices. In addition, under the provisions of the *Energy Policy Act* of 2005, the NGA was amended to prohibit market manipulation in connection with the purchase or sale of natural gas and the FERC established regulations to increase natural gas pricing transparency by requiring certain market participants to report their gas sales transactions annually to the FERC. Facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Although FERC has set forth a general test to determine whether facilities are exempt from FERC jurisdiction as "gathering" facilities, FERC's determinations as to the classification of facilities are performed on a case-by-case basis and FERC has the authority to reclassify facilities previously thought to be non-jurisdictional. The FERC regulates interstate natural gas transportation rates and service conditions under the NGA and the *Natural Gas Policy Act* of 1978 (the "**NGPA**"), which affects the marketing of natural gas, as well as revenues we may receive for sales of our natural gas. Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies.

In both Canada and the United States, exporters are free to negotiate prices and other terms with purchasers, provided that the export contract meets certain criteria prescribed by the CER and the Government of Canada or, in relation to United States exports, restrictions on export licenses imposed by the DOE. Natural gas may not be exported from Canada without a license or order from the CER or imported into the United States or exported from the United States without a license from the DOE. Licenses to export or import natural gas may include various terms and conditions with respect to duration, quantity, tolerance levels, points of exportation or importation, environmental requirements, among other factors and, in Canada, for export, may be obtained for a period that does not exceed 40 years. In Canada the approval of the Minister of Natural Resources and the Governor in Council is currently required prior to the issuance of a license to export natural gas. Alternatively, natural gas may be exported from Canada pursuant to an order from the CER. Orders may be obtained for a period of two years or less or for a period greater than two years but less than 20 years, where the quantity is not more than 30,000 m^3/day. Orders do not require the approval of the Governor in Council or the Minister of Natural Resources. Any person who imports oil or gas into Canada must provide prescribed information in the prescribed form and manner to the CER, but does not require a license. In the United States, the DOE regulates the exportation and importation of natural gas, including liquefied natural gas. U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a free trade agreement with the United States that provides for national treatment of trade in natural gas, however, the DOE's regulation of imports and exports from and to countries without such free trade agreements is more comprehensive. The FERC also regulates the construction and operation of import and export facilities.

The Canada-United States-Mexico Agreement and The North American Free Trade Agreement

On July 1, 2020, the Canada-United States-Mexico Agreement ("**CUSMA**") came into force replacing the North American Free Trade Agreement ("**NAFTA**").

Relevant to the energy industry, CUSMA does not contain the proportionality rules found in NAFTA's Article 605 whereby Canada remained free to restrict exports to the U.S. or Mexico provided that such export restrictions did not: (i) reduce the proportion of the energy resource exported relative to the total supply of that energy resource in Canada as compared to the proportion prevailing in the most recent 36-month period; (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply.

CUSMA also eliminates certain tariffs on some diluents used to transport heavy oil from Canada to the U.S.

There has been little to no effect on Canada's energy industry by the ratification of CUSMA and Crescent Point has not experienced any significant change to its operations or marketing activities as a result of the ratification of CUSMA.

Royalties and Incentives

In addition to federal regulation, each province (and in the case of the U.S., each state) has legislation with respect to oil and gas activities, governing matters such as land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions where we operate, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands (or in the case of the U.S., lands other than federal lands) are determined by negotiations between the mineral owner and the lessee. Crown royalties (or in the case of the U.S., federal royalties) are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity and depth, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the governments of Canada, British Columbia, Alberta, Saskatchewan and Manitoba have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. Such programs are generally introduced when commodity prices are low, and are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. These programs reduce the amount of Crown royalties otherwise payable.

Alberta

In terms of oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. In respect of freehold lands, royalties are payable to the mineral owner and taxes are payable to the Province of Alberta. The Government of Alberta's approach to the royalty and tax regime is regularly reviewed for compliance with the purpose of the regimes to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees.

On January 1, 2017, Alberta adopted a new, modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") continues to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands, which remain subject to their pre-existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the AER on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward as the mature well's production declines.

As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Old Framework range from a base rate of zero to a cap of 40%.

The Old Framework also includes a natural gas royalty formula, which formula provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%.

Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Alberta Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

Incentive Programs

A number of incentive programs, including the Enhanced Oil Recovery Royalty Program (the "**EOR Program**") were created pursuant to the Old Framework.

Under the EOR Program, Alberta Energy may approve royalty reductions for qualifying enhanced oil recovery projects. Applications under the EOR Program ceased being accepted as of December 31, 2016, however, the EOR Program continues to apply to schemes previously approved thereunder, and will continue to so apply until December 31, 2026.

Under the Modernized Framework, two strategic programs were introduced with the intention of promoting expanded production potential and generating long-term returns to the Province of Alberta.

The Enhanced Hydrocarbon Recovery Program (the "**EHR Program**") began January 1, 2017, and replaced the EOR Program. The EHR Program is intended to promote incremental production through enhanced recovery methods and consists of two main components. The first component targets tertiary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or other approved methods. The second component targets secondary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by waterflooding, gas cycling, gas flooding, polymer flooding or other approved methods. Under both components of the program, a company pays a flat royalty of 5% on crude oil, natural gas and natural gas liquids produced from wells in an approved scheme for a limited benefit period. After the benefit period ends, wells in these schemes are subject to normal royalty rates under the Modernized Framework.

The Emerging Resources Program (the "**ERP**") began January 1, 2017. The ERP is intended to encourage industry to open up new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. For the purposes of the ERP, a project consists of a defined geographic area, target formation, set of wells and associated infrastructure. Wells that receive program benefits pay a flat royalty rate of 5% on revenues until their combined revenue equals their combined program specific cost allowances established under the ERP, which replace the standard Drilling and Completion Cost Allowance under the Modernized Framework in respect of such wells. After achieving payout of the specific cost allowance, wells are subject to normal royalty rates under the Modernized Framework.

Saskatchewan

With respect to production obtained from provincial Crown lands in the Province of Saskatchewan, the amount payable as a royalty in respect of crude oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month and the price of the oil. For both Crown royalty and freehold production tax purposes, crude oil is categorized by oil type as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". Additionally, the oil in each category is subdivided according to the conventional royalty and production tax classifications as "fourth tier oil", "third tier oil", "new oil", or "old oil". The royalty reserved to the Crown depends on the categorization and classification of the oil, monthly production, and a prescribed reference price determined monthly by the Saskatchewan Ministry of Energy and Resources ("**SMER**").

Similarly, the amount payable as a royalty in respect of natural gas in the Province of Saskatchewan depends on the vintage of the gas, the type of gas production, the quantity of gas produced in a month, and the price of the gas. For both provincial Crown royalty and freehold production tax purposes, natural gas is categorized as either non-associated gas or associated gas, the former being gas produced from gas wells and the latter being gas produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as "fourth tier gas", "third tier gas", "new gas", or "old gas". The royalty reserved to the Crown depends on the categorization and classification of the natural gas, monthly production, and a reference price prescribed by the SMER. As an incentive for the production and marketing of natural gas which may otherwise have been flared, the royalty rate on associated gas is less than on non-associated natural gas.

Approximately 17% of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the provincial Crown. With respect to production from freehold lands, the tax levied on oil and gas production in the Province of Saskatchewan will depend on the classification of the oil or gas and the relevant Crown royalty rate.

Incentive Programs

On October 1, 2002, a modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from qualifying oil wells and gas wells in the Province of Saskatchewan with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%. In addition, oil produced from Enhanced Oil Recovery ("**EOR**") projects that commenced operation prior to April 1, 2005 are subject to a cost sensitive royalty regime determined by prescribed formulas which include a number of variables and which differentiate between pre- and post-project payout. EOR projects that commenced operation on or after April 1, 2005 are also subject to a cost sensitive royalty regime that provides a royalty of 1% of gross EOR revenues prior to project payout and 20% of EOR operating income after project payout and a freehold production tax rate of 0% prior to payout and 8% of EOR operating income after payout. In respect of new waterflood projects, or expansions of existing waterflood projects, that have been approved by the minister and that commenced operation on or after October 1, 2002, the incremental oil produced from the project as a result of the waterflood operations qualifies for the "fourth tier oil" Crown royalty and freehold production tax rates.

In April of 2013, the SMER announced three new drilling incentives for wells drilled on or after October 1, 2002: the vertical well drilling incentive (the "**VWDI**"); the horizontal well drilling incentive (the "**HWDI**"); and the exploratory gas well drilling incentive (the "**EGWDI**"). The VWDI provides a royalty reduction to 2.5% and a freehold production tax rate of 0% for fixed volumes drilled from exploratory vertical oil wells and deep development vertical oil wells. Exploratory vertical oil wells are wells that meet certain prescribed criteria showing the well produces oil from an area which has not generally seen production. The incentive for exploratory vertical oil wells applies to the produced volume up to 16,000m³, depending on depth. Deep development vertical oil wells are deep or deepened wells, that are not exploratory oil wells, drilled to certain prescribed zones. The incentive for these wells applies to the produced volume up to 8,000 m³. The HWDI is very similar to the VWDI, but applies to non-exploratory horizontal wells drilled on or after October 1, 2002 and provides the incentive to produced volumes up to 16,000 m³, depending on depth. Finally, the EGWDI provides a royalty reduction of the lesser of the fourth tier gas royalty rate (between 0%-5%) or 2.5% and a 0% freehold production tax rate. The incentive applies to wells that meet certain prescribed criteria which show that the well produces gas from an area from which gas has not generally been produced. The incentive applies to the produced volume up to 25,000,000 m³.

In December 2018, the Government of Saskatchewan introduced the Waterflood Development Program (the "**WDP**"), which program offers repayable royalty and freehold production tax deferrals for eligible wells that have been converted to injection wells or newly drilled injection wells for the purpose of waterflooding an oil reservoir. Under the WDP, royalty and freehold production taxes can be deferred for a period of three years and can be used alongside other incentive grant programs available in Saskatchewan.

In June of 2019, the Government of Saskatchewan introduced the Saskatchewan Petroleum Innovation Incentive ("**SPII**"). SPII offers transferable royalty and freehold production tax credits for qualified innovation commercialization projects at a rate of 25% of eligible project costs, targeting a broad range of innovations across all segments of Saskatchewan's oil and gas industry.

On August 1, 2019 the Government of Saskatchewan introduced the Oil and Gas Processing Investment Incentive ("**OGPII**"). OGPII offers transferable royalty and freehold production tax credits for qualified greenfield or brownfield value-added projects at a rate of 15% of eligible project costs.

In March 2020, the Government of Saskatchewan introduced the Oil Infrastructure Investment Program ("**OIIP**"), which program offers transferable oil and gas royalty and freehold production tax credits for qualified projects at a rate of 20 percent of eligible project costs (with a minimum $10 million investment). OIIP is open to new or expanded oil, refined petroleum products or natural gas liquids, including transmission pipelines, feeder pipeline and pipeline terminals. As of November 4, 2021, carbon dioxide pipeline projects became eligible for OIIP, including pipeline projects to be used for transporting carbon dioxide for carbon capture and storage or for EOR projects.

Effective April 1, 2021, Saskatchewan amended the High Water-Cut Oil Well Program, which program provides a royalty status re-assignment for qualifying high water-cut oil wells that incur an average minimum investment of $20,000 per well, made on or after April 1, 2021, to directly improve water handling capabilities and extend the producing life of the well. Such eligible wells drilled before October 1, 2002 will receive fourth tier royalties on all future incremental high water-cut oil production, and wells drilled on or after October 1, 2002 will obtain a 2 percent royalty rate reduction on all future oil production.

On April 6, 2021, the Government of Saskatchewan introduced the Associated Gas Royalty Moratorium, which is a moratorium on the collection of Crown royalty and freehold production tax on associated gas produced from wells other than gas wells, including natural gas produced from oil wells. The moratorium has been implemented as part of Saskatchewan's Methane Action Plan to assist producers in meeting regulatory obligations to reduce methane-based greenhouse gas emissions by 40-45 percent between 2020 and 2025. The moratorium applies to associated natural gas produced on or after April 1, 2021, and before April 1, 2026.

North Dakota

Royalties payable for oil and gas production vary depending on whether the oil and gas estate is owned by the federal government, the state government, an Indigenous tribe or person, or a private landholder. Generally, the current federal royalty rate for onshore oil and gas is 12.5%. Production in North Dakota may be subject to oil and gas severance taxes, although such severance tax includes exemptions available for low-producing wells. Oil and gas produced from North Dakota state oil and gas leases is subject to royalties ranging from 1/8 to 3/16 of the net mineral interests of all oil and gas produced depending on location. Royalties payable under private oil and gas leases in North Dakota are determined by negotiations between the mineral owner and the lessee.

The North Dakota Industrial Commission (the "**NDIC**") regulates the drilling and production of crude oil and natural gas in North Dakota. Over the past decade, the NDIC has adopted more stringent rules relating to production activities, including waste discharges and storage, financial assurance for wells and underground gathering pipelines, hydraulic fracturing, and associated public disclosure on the FracFocus chemical disclosure registry. Additionally, in response to North Dakota natural gas production reaching record highs and flaring levels exceeding the state's limit of acceptable levels, the NDIC announced an initiative in 2014 to reduce flaring and maximize the value of natural gas and natural gas liquids ("**NGLs**") that are co-produced with the state's oil production. Specifically, the NDIC established requirements on oil and gas operators to capture, and thus not flare, a designated percentage of the natural gas produced from wells in North Dakota, subject however, to numerous exceptions and variances. For the period ending October 31, 2020, the gas capture requirement was 88%, which was increased to 91% for periods on and after November 1, 2020. If the applicable gas capture requirement is not met, potential penalties may be imposed unless an exception or variance applies. On November 15, 2019, the NDIC held a public hearing on improving its gas capture strategy and promoting "regulatory clarity needed around gas gathering agreements." The NDIC seeks to avoid service interruptions on gathering lines, which have caused some of the recent excess flaring.

Finally, the NDIC has adopted rules that improve the safety standards for transporting Bakken crude oil by establishing operating standards for conditioning equipment to properly separate production fluids, limits to the vapor pressure of produced crude oil, and parameters for temperatures and pressures associated with the production equipment.

Environmental Regulation and Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, state, territorial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced or used in association with oil and gas operations, as well as requirements with respect to oilfield waste handling, storage and disposal, land reclamation, habitat and endangered species protection, and minimum setbacks of oil and gas activities from sensitive receptors.

Canada

Provincial environmental legislation in the Province of Alberta for the oil and gas industry is, for the most part, set out in the *Environmental Protection and Enhancement Act*, the *Oil and Gas Conservation Act*, the *Pipeline Act*, the *Water Act* and the *Technology and Emissions Reductions Implementation Act, 2019,* which impose strict environmental standards with respect to releases of effluents and emissions, including monitoring and reporting obligations, and impose significant penalties for non-compliance. Provincial environmental legislation in the Province of Saskatchewan is, for the most part, set out in *The Environmental Management and Protection Act*, *2010*, *The Saskatchewan Environmental Code, The Oil and Gas Conservation Act*, *The Pipeline Act, 1998* and *The Management and Reduction of Greenhouse Gases Act* which regulate harmful or potentially harmful activities and substances and GHGs, any release of such substances, and remediation and abandonment obligations in Saskatchewan. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require an environmental impact assessment under the provincial *Environmental Assessment Act*. Provincial environmental legislation in the Province of Manitoba is, for the most part, set out in the *Environment Act* and the *Oil and Gas Act*.

Environmental legislation also requires that wells, pipelines and facility sites be constructed, operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, or in the suspension or revocation of necessary licenses and approvals. Crescent Point may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject Crescent Point to statutory strict liability in the event of an accidental spill or discharge from a well, pipeline or facility, meaning that fault on the part of Crescent Point need not be established if such a spill or discharge is found to have occurred.

Crescent Point estimates abandonment and reclamation costs by taking into consideration the costs associated with decommissioning, abandonment, remediation and reclamation, all adjusted according to its working interest and discounted in accordance with NI 51-101. Decommissioning liability cost estimates are based on information published by the AER with respect to the AER liability management programs in Alberta and published by SMER in Directive PNG025 Financial Security Requirements Saskatchewan. Crescent Point has procedures in place which address various matters including: spill prevention, response, notification, reporting, remediation and reclamation; environmental monitoring; government inspections; surface equipment spacing requirements; facility protection/ security; vegetation management; surface water run-off/run-on management; groundwater; noise control; atmospheric emissions; wellsite reclamation; earthen pits; storage tanks; naturally occurring radioactive materials; disposal wells; suspended or shut-in wells; waste management; and communications.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil, or water may give rise to liabilities to third parties or regulators or result in the suspension or revocation of regulatory approvals and may require Crescent Point to incur costs to remedy such a discharge in an event not covered by Crescent Point's insurance, which insurance is in line with industry practice. Furthermore, Crescent Point expects incremental future costs associated with compliance with increasingly complex environmental protection requirements with respect to GHG emissions or otherwise, some of which may require the installation of emissions monitoring and measuring devices, the verification and reporting of emissions data and additional financial expenditures to comply with GHG emissions reduction requirements.

United States

Our wholly owned subsidiary, CPEUS, owns oil and natural gas properties and related assets in North Dakota and Montana in the United States. CPEUS' oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order 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. CPEUS' operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

The following is a summary of the more significant existing environmental, health and safety laws and regulations in the United States to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The *Comprehensive Environmental Response, Compensation, and Liability Act* ("**CERCLA**") and comparable state statutes impose strict, joint and several, and retroactive liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the government or private parties to file claims requiring cleanup actions, demands for reimbursement for cleanup costs, or natural resource damages, or for neighboring landowners and other third parties to file tort claims for bodily injury and property damage allegedly caused by hazardous substances released into the environment. CERCLA currently excludes petroleum from its definition of "hazardous substance", but related substances such as BTEX chemicals are listed. Additionally, on September 6, 2022, the US Environmental Protection Agency (the "**EPA**") published a Proposed Rule to designate two per and polyfluoroalkyl substances ("**PFAS**") perfluorooctanoic acid ("**PFOA**") and perfluorooctane sulfonic acid ("**PFOS**") as "hazardous substances" under CERCLA. If these PFAS are listed as CERCLA hazardous substances and PFAS contamination is detected at sites that we currently own or operate, or formerly owned or operated, we may be obligated to remediate those areas.

The federal *Solid Waste Disposal Act,* as amended by the *Resource Conservation and Recovery Act*, (collectively, "**RCRA**") and comparable state statutes regulate the generation, transportation, treatment, storage and disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance, as well as requirements for corrective actions. Under the RCRA oil and gas exploration and production waste ("**E&P waste"**) exemption, E&P waste is regulated as a "solid waste" rather than a "hazardous waste." However, these E&P wastes may still be regulated under state solid waste laws and regulations. On several occasions in the past decade, environmental groups have sued the EPA for failing to update and revise RCRA regulations, including the regulations governing E&P waste. In each case, EPA has determined that regulatory revisions are not necessary. However, there remains a risk that the EPA could make changes in the current RCRA E&P waste exemption, which, in turn, could result in an increase in the costs to manage and dispose of wastes. Additionally, there is a risk that certain states may regulate E&P wastes more stringently, which could also result in an increase in the costs to manage and dispose of wastes. Also, ordinary industrial wastes that are not uniquely associated with oil and gas exploration and production operations, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous waste. Although we do not believe the current costs of managing our materials constituting wastes (as they are presently classified) to be significant, any repeal or modification of the E&P waste exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Other statutes relating to the storage and handling of pollutants include the *Oil Pollution Act* of 1990 (the "**OPA**"), which requires certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The OPA contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. State laws mandate oil cleanup programs with respect to contaminated soil. A failure to comply with the OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

The *Endangered Species Act* (the "**ESA**") seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, or destroy or modify the critical habitat of such species. Under the ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize such species or their habitat. The ESA has been used to prevent or delay drilling activities and provides for criminal penalties for willful violations of its provisions. Recent changes to the ESA, if they survive legal challenge, would change the scope of the rule's application. In August 2019, the Trump administration issued three final rules regarding implementation of the ESA (the "**2019 Rules**"). Under the new rules, the administration changed the considerations for listing, delisting or reclassifying species. The 2019 Rules limit the framework for the term "foreseeable future," a standard used to determine whether a species is threatened, to reference a period as long as the conditions posing a danger are probable. The 2019 Rules also indicate that, when dedicating critical habitat, occupied spaces are considered first to lessen the regulatory burdens on unoccupied spaces. Unoccupied spaces must be proven essential to conservation and must contain physical or biological features essential to that species' conservation. Additionally, the final rules removed the phrase "without reference to possible economic or other impacts of such determination" of a species' status, which could open determinations for listing species to economic considerations. A second rule revised the rule related to threatened species to remove the default extension of most of the prohibitions for activities involving endangered species to threatened species, making it a case-by-case determination. These new rules applied only towards future listing of species, and significantly limited the scope of the ESA. However, the Biden administration announced in June 2021, that it will formally introduce regulatory proposals to rescind changes the Trump administration made to the ESA regulations. The rules also are being challenged in federal courts in California and Hawaii, and in November 2022, the California court decided to leave the rules in effect pending remand to the U.S. Fish and Wildlife Service ("**FWS**"). The Biden administration has not yet proposed new rules.

Additionally, the Biden administration announced in October 2021 that it will formally introduce regulatory proposals to rescind other changes the Trump administration made to the ESA regulations. On June 24, 2022, the Biden administration published a final rule that rescinded the Trump administration's definitions of "habitat", finding that the definition impeded the FWS's ability to designate critical habitat based on the best scientific data available. Similarly, on July 21, 2022, the FWS published a final rule rescinding the Trump administration's rules that changed the FWS's process for excluding areas from critical habitat designation and undertaking exclusion analyses, thus reinstating the rules in place prior to 2021. If the Biden administration continues to rescind the Trump administration's revisions to the ESA regulations, we, as well as our competitors, would be expected to incur increased operating expenses and potential delays in our operations in the United States. Other statutes that provide protection to animal and plant species and that may apply to our operations include, without limitation, the *Fish and Wildlife Coordination Act*, the *Fishery Conservation and Management Act*, the *Migratory Bird Treaty Act*, and the *Bald and Golden Eagle Protection Act*.

The *National Environmental Policy Act* ("**NEPA**") requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal and certain Indigenous lands would result in a "significant impact" on the environment. For purposes of NEPA, "major federal action" can be something as basic as issuance of a required permit. For oil and gas operations on federal and certain Indigenous lands or requiring federal permits, NEPA review can increase the time for obtaining approval and impose additional regulatory burdens on the natural gas and oil industry, thereby increasing our costs of doing business and our profitability. On July 16, 2020, the White House Council on Environmental Quality ("**CEQ"**) published a Final Rule revising NEPA's implementing regulations (the "**2020 Rule**"). The changes to NEPA introduced a "non-major" category which would exempt certain types of governments, allowing them to move forward without an environmental assessment. The changes also eliminate reference to "cumulative" effects and focus more on causation. This would limit the scope of the assessment and narrow the environmental effects associated with the proposed action to those expected as a direct outcome, rather than assessing indirect effects and their cumulative impact. The 2020 Rule would make the NEPA process more efficient and less time consuming by streamlining the entire process and proposing page and time limits. Additionally, the Final Rule introduced additional responsibilities for commenters. For example, comments would be allowed during the scoping period, and if a commenter fails to raise certain issues at the onset of the project those issues may be deemed waived. This may have the effect of less or quicker judicial review, if the issues are waived. The Final Rule would likely result in a quicker turnaround time for obtaining leases and permits. Twenty-three states and several environmental groups filed two separate lawsuits in California federal court challenging the Final Rule. Notably, on January 20, 2021, President Biden issued Executive Order 13990, which directed federal agencies to immediately review and take action to address the promulgation of federal regulations during the previous administration that conflicted with important national objectives. The Executive Order specifically identified the 2020 Rule as subject to the Executive Order's requirements. Accordingly, on February 12, 2021, the California District Court issued a stay in both cases to provide CEQ with adequate time to reconsider the 2020 Rule, as directed by the Executive Order. The two lawsuits are currently stayed to accommodate revision of the rules.

In addition, in October 2021, the CEQ published a notice of proposed rulemaking (the "**2021 Proposed Rule"**) to reverse several of the Trump administration's revisions to the NEPA implementing regulations. The 2021 Proposed Rule seeks to revise three aspects of the 2020 Rule back to the prior regulations with minor modifications: (i) the "purpose and need" of a proposed action; (ii) the definition of "effects," restoring the prior definitions of direct, indirect, and cumulative effects; and (iii) agency flexibility to develop NEPA implementation procedures that go beyond the CEQ regulatory requirements. CEQ published the 2021 Proposed Rule as a final rule on April 20, 2022, and the rule became effective May 20, 2022. CEQ has announced that it intends to propose a second phase of rulemaking to implement additional revisions to the 2020 Rule to ensure efficient and effective environmental reviews, provide regulatory certainty, promote better decision-making and address climate change and environmental justice objectives.

The *Clean Water Act* (the "**CWA**") and comparable state statutes, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. To the extent the agencies' are expanding the range of properties subject to the CWA jurisdiction, certain energy companies could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which in turn could reduce demand for our services. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. The CWA regulates stormwater run-off from oil and natural gas facilities and requires a stormwater discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample stormwater run-off from its operations. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in waters of the United States ("**WOTUS**") unless authorized by an appropriately issued permit.

On April 21, 2020, the EPA and U.S. Army Corps of Engineers ("**USACE**") released a final rule to define WOTUS (the "**2020 WOTUS Rule"**) that identified four categories as jurisdictional WOTUS: (i) the territorial seas waters that are currently used, or were used in the past, or may be susceptible to use, in interstate or foreign commerce, including waters that are subject to the ebb and flow of the tide ("**Traditional Navigable Waters"** or "**TNW"**) and any TNW that have been, are, or could be used in interstate or foreign commerce; (ii) tributaries of TNW, which are naturally occurring surface water channels that contribute perennial or intermittent flow into a TNW "in a typical year," either directly or indirectly; (iii) ditches, which are artificial channels used to convey water that are either TNWs, constructed in a tributary, or constructed in an adjacent wetland; (iv) lakes and ponds that contribute perennial or intermittent surface flow to a TNW, tributary of a TNW, or a wetland adjacent to a TNW, or are flooded by another jurisdictional WOTUS in a typical year; (v) impoundments of other jurisdictional WOTUS; and (vi) adjacent wetlands, which must actually abut a jurisdictional WOTUS or have a direct hydrological surface connection to a jurisdictional WOTUS in a typical year, TNW, tributary, or lake, pond, or impoundment of a TNW.

However, the 2020 WOTUS Rule was vacated by two separate federal district courts in late 2021. On November 18, 2021, EPA and USACE issued a pre-publication version of another rule largely reinstating the previous 1986 WOTUS rule and guidance "with certain amendments" to reflect "consideration of the agencies statutory authority under the CWA and relevant Supreme Court decisions" (the "**2021 Proposed Rule"**). The 2021 Proposed Rule was published in the Federal Register on December 7, 2021. In addition to the 2021 Proposed Rule, the EPA and USACE plan to develop yet another amendment to the WOTUS regulations, which will build upon the regulatory foundation in the 2021 Proposed Rule with the benefit of additional stakeholder engagement and public input. In September 2022, EPA and USACE sent the draft final rule to implement the 2021 Proposed Rule to the Office of Management and Budget for interagency review, but no final rule has yet been issued by the agencies. It is unknown at this time when the 2021 Proposed Rule will take effect; when the next forthcoming proposed amendments are expected; and/or whether either new rule will be challenged and withstand any challenges in federal court. Finally, in January 2022, the United States Supreme Court granted review of Sackett vs. EPA, which involves issues related to CWA scope and jurisdiction and could impact the current rulemaking process. The Supreme Court heard oral argument in Sackett on October 3, 2022, and a decision is expected in 2023. Although the outcome of the 2021 Proposed Rule and additional forthcoming amendments to the WOTUS regulations is unknown, the regulations under the Biden Administration are undoubtedly more stringent in terms of the scope of WOTUS, which could ultimately change the scope of the CWA's jurisdiction and result in increased costs and delays with respect to obtaining permits for discharges of pollutants or dredge and fill activities in waters of the U.S., including regulated wetland areas. However, the definition of "WOTUS" and how it has been applied has been in flux over the last several years, both via administrative rulemakings and actions and judicial interpretation and intervention. Thus, the fate of the definition of "WOTUS" under the CWA and how that ultimately will be applied by the Agencies is yet to be seen.

On January 19, 2017, the EPA issued the final 2017 construction general permit ("**CGP**") for stormwater discharges from construction activities involving more than one acre, which provides coverage for a five-year period and which took effect on February 16, 2017. On January 18, 2022, EPA issued its 2022 CGP for stormwater discharges from construction activities involving more than one acre. The 2022 CGP, which became effective February 17, 2022, replaces the 2017 CGP. The 2022 CGP implements Effluent Limitations Guidelines and New Source Performance Standards for the Construction and Development Industry. The rule includes stringent restrictions on erosion and sediment control, pollution prevention and stabilization. The 2022 CGP provides permit coverage for certain stormwater discharges from construction activities at facilities where EPA is the permitting authority for a five-year period through February 16, 2027.

The *Safe Drinking Water Act* (the "**SDWA**") and the Underground Injection Control ("**UIC**") program promulgated thereunder, regulate the drilling and operation of subsurface injection wells. The EPA directly administers the UIC program in some states and in others the responsibility for the program has been delegated to the state. The program requires that a permit be obtained before drilling a disposal well. Violation of these regulations and/or contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third-party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Some of our operations employ hydraulic fracturing techniques to stimulate oil and natural gas production from unconventional geological formations, which entails the injection of pressurized fracturing fluids into a well bore. The federal *Energy Policy Act* of 2005 amended the SDWA to exclude hydraulic fracturing from the definition of "underground injection" under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, previously have been introduced in Congress, without success. However, with the changes in the U.S. presidential administrations and the control of Congress, such legislation may have a better chance of passing in the future. In addition, the EPA at the request of Congress conducted a national study examining the potential impacts of hydraulic fracturing on drinking water resources. The final report, *Hydraulic Fracturing for Oil* *and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States*, was issued in December 2016. The report raised some concerns regarding potential vulnerabilities in the process that could impact drinking water. However,

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the EPA noted that data gaps and uncertainties limited the agency's ability to draw conclusions about the impact of hydraulic fracturing activities on drinking water sources.

Many states currently independently regulate hydraulic fracturing operations in the state, including North Dakota and Montana. If new federal rules or new state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business. It is also possible that our drilling and injection operations could adversely affect the environment, which could result in a requirement to perform investigations or clean-ups or in incurring other unexpected material costs or liabilities.

The *Clean Air Act* ("**CAA**"), as amended, restricts the emission of air pollutants from many sources, including oil and gas operations. The CAA and regulations implemented thereunder regulate oil and natural gas production, processing, transmission and storage operations under the New Source Performance Standards ("**NSPS**") and National Emission Standards for Hazardous Air Pollutants programs. CAA regulations include NSPS for completions of hydraulically fractured wells. In 2016, the EPA issued rules to curb methane emissions and reduce the release of volatile organic compounds and toxic air pollutants from new and modified oil and gas sources (the "**2016 Rule**"). The final rules covered emissions from additional equipment and activities in the oil production chain, including hydraulically fractured oil wells which were not previously regulated. Additionally, the rules required owners/operators to find and repair leaks to reduce fugitive emissions, which included increasing the frequency of monitoring equipment. On March 12, 2018, the EPA issued two final amendments to certain provisions of the 2016 Rule. The amendments addressed the requirement that leaky components be repaired during unplanned or emergency shutdowns and monitoring survey requirements for well sites located on the Alaskan North Slope.

In September 2020, the EPA finalized a new rule that amended the 2016 Rule (the "**2020 EPA Rule**"). In the 2020 EPA Rule, the EPA removed all sources in the transmission and storage segment of the oil and natural gas industry from regulation. The 2020 EPA Rule also rescinded the methane requirements in the 2016 Rule and reduced monitoring frequencies. On June 30, 2021, President Biden signed into law a joint Congressional resolution disapproving and invalidating much of the 2020 EPA Rule under the prior Administration, including the 2020 EPA Rule's rescission of the methane requirements.

On November 15, 2021, EPA published a proposed rule that would update and expand existing requirements for the oil and gas industry, as well as create significant new requirements and standards for new, modified and existing oil and gas facilities. The proposed new requirements would include, for example: (i) updated and broadened methane and volatile organic compound emission reduction requirements for new, modified, and reconstructed oil and gas sources, including standards that limit emissions from additional types of sources (such as intermittent vent pneumatic controllers, associated gas, and well liquids unloading); and (ii) requirements that states develop plans to limit methane emissions from hundreds of thousands of existing sources nationwide, along with presumptive standards for existing sources to assist in the planning process. Key features of the November 2021 proposed rule include:

- a comprehensive monitoring program for new and existing well sites and compressor stations;
- a compliance option that allows owners and operators the flexibility to use advanced technology that can find major leaks more rapidly and at lower cost;
- a zero-emissions standard for new and existing pneumatic controllers;
- standards to eliminate venting of associated gas, and require capture and sale of gas where a sales line is available, at new and existing oil wells;
- proposed performance standards and presumptive standards for other new and existing sources, including storage tanks, pneumatic pumps, and compressors; and
- a requirement that states meaningfully engage with overburdened and underserved communities, among other stakeholders, in developing state plans.

On November 8, 2022, EPA published a supplemental proposal to update, strengthen, and expand the standards proposed in November 2021. The proposed rules for new and modified facilities are estimated to be finalized by the end of 2023, while any standards finalized for existing facilities will require further state rulemaking actions over the next several years before they become applicable and effective. If this proposed rule is implemented, it would be expected to cause us, as well as our competitors, to incur increased operating expenses.

We are subject to a number of federal and state laws and regulations, including the federal *Occupational Safety and Health Act* ("**OSHA**") and comparable state laws, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal *Superfund Amendment and Reauthorization Act* and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. Specifically, OSHA has enacted a regulation regarding crystalline silica exposures, which included requirements that hydraulic fracturing operations implement dust controls to limit exposures to the substance.

Transportation and safety of natural gas is also subject to regulation by the U.S. Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration ("**PHMSA"**), under the *Natural Gas Pipeline Safety Act* of 1968, as amended, which imposes safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities, the *Pipeline Inspection, Protection, Enforcement and Safety Act* of 2006, the *Pipeline Safety, Regulatory Certainty and Job Creation Act* of 2011, and the *Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act)* of 2020. In November 2021, PHMSA issued its final rule extending reporting requirements to all onshore gas gathering operators and applying a set of minimum safety requirements to certain onshore gas gathering pipelines with large diameters and high operating pressures. Furthermore, in August 2022, PHMSA published a final rule in the Federal Register that establishes new standards for identifying threats, potential failures, and worst-case scenarios resulting from pipeline incidents. The final rule also institutes new management of change requirements, strengthens PHMSA's integrity management requirements and corrosion control standards, and implements new requirements for inspections after extreme weather events. The final rule becomes effective on May 24, 2023. These new rules could bring certain pipelines under federal scrutiny for the first time and/or increase the cost of compliance with PHMSA's standards.

We are subject to federal and state laws and regulations relating to preservation and protection of historical and cultural resources. Such laws include the *National Historic Preservation Act*, the *Native American Graves Protection and Repatriation Act*, *Archaeological Resources Protection Act*, and the *Paleontological Resources Preservation Act*, and their state counterparts and similar statutes, which require certain assessments and mitigation activities if historical or cultural resources are impacted by our activities and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements.

Greenhouse Gas Emissions

Carbon Policy

In November 2015, Canada participated in the twenty first session of the Conference of the Parties of the United Nations Framework Convention on Climate Change ("**COP 21**") in Paris, France, the goal of which was to reach a new agreement for fighting global climate change. COP 21 resulted in the adoption of the Paris Agreement which made several recommendations, including: (i) holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change; (ii) increasing the ability to adapt to the adverse impacts of climate change and fostering climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production; and (iii) making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development. The Paris Agreement came into force on November 4, 2016.

Over the last several years, the federal government has undertaken a number of initiatives to achieve domestic GHG reductions that align with its commitments made under the Paris Agreement. These measures include regulations, codes and standards, targeted investments, incentives, tax measures and programs intended to directly and indirectly reduce GHG emissions.

On June 21, 2018, the Government of Canada brought into force a pan-Canadian approach to the pricing of GHG emissions under the *Greenhouse Gas Pollution Pricing Act* ("**GGPPA**"). The federal carbon pollution pricing system has two parts: (i) an emission reduction and trading system for large industry, known as the output-based pricing system ("**OBPS**"); and (ii) a regulatory charge on 21 types of fuel, commonly known as the carbon tax. Each province was given the choice to either accept the federal requirement in full; create their own carbon pricing policies that meet federal standards; or a hybrid approach. Both Saskatchewan and Alberta have opted for the hybrid approach, where they have committed to develop province specific output-based pricing systems but are subject to the federal carbon tax on fuel. The federal carbon tax is applied on a broad set of fuels at $50 per tonne of GHG emissions in 2022 and will increase to $65 per tonne in 2023 and then by $15 per tonne per year until it reaches $170 per tonne in 2030.

The federal government also has a GHG emission reporting requirement under the *Canadian Environmental Protection Act, 1999* ("**CEPA**") whereby facilities that emitted 10,000 tonnes or more of GHGs per year must report their emissions to Environment and Climate Change Canada. On June 21, 2022, the federal government also brought into force the *Clean Fuel Regulations* which set emission limits on a variety of liquid fuels, including gasoline and diesel.

On July 18, 2022, the federal government published a discussion paper on two options to implement a cap on oil and gas emissions, being either a new cap and trade system or modification to the OBPS. The precise timing of the federal government's next steps in developing the oil and gas cap will depend upon the option chosen and the final design of the cap. The oil and gas emissions cap is expected to set out a specific trajectory for the oil and gas sector to achieve net zero emissions by 2050.

In Alberta, GHG emissions are regulated under the *Emissions Management and Climate Resilience Act* and the TIER Regulation, which came into effect January 1, 2020. The TIER system is mandatory for large emitters, being those that emit 100,000 tonnes or more of GHGs per year, however, facilities with less than 100,000 tonnes per year can voluntarily opt into the system by aggregating two or more smaller facilities together. Registered facilities are required to reduce their emission intensity (tCO2e/boe) by 10% based on a historical benchmark. Companies may meet these required reductions through improvements to their operations; by purchasing and retiring Alberta-based emission reduction or offset credits; by contributing to the provincial TIER Compliance Fund; or by a combination of these actions. Any facility registered into the TIER system can apply to the Canadian Revenue Agency and receive an exemption from the federal fuel surcharge (carbon tax) on applicable fuel combustion and flaring. Crescent Point has two aggregate facilities registered in the TIER system.

On December 15, 2022, the Government of Alberta announced amendments to TIER which became effective on January 1, 2023, which amendments include meeting federal emission reduction requirements for 2023 through 2030, compliance flexibility and increasing the regulator stringency.

On January 1, 2019, the Government of Saskatchewan brought into force *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations* (the "**MRGHGR**") to regulate greenhouse gas emissions in the province. As part of the MRGHGR, the Output-Based Performance Standards ("**the Saskatchewan OBPS**") were developed to reduce emissions intensity associated with stationary fuel combustion by 15% by 2030, however, subsequently, effective January 1, 2023, emissions intensity associated with stationary fuel combustion and flaring were reduced by 20% by 2030. Under the Saskatchewan OBPS program operators of certain large facilities that emit 25,000 tonnes or more of GHGs per year must register. Additionally, a voluntary aggregated facility (two or more smaller facilities grouped together) can also register in the OBPS program. Operators must reduce their emissions per unit of production from their historical emissions and may meet these required reductions through improvements to their operations; by purchasing and retiring emission reduction or offset credits; by contributing to the provincial Technology Fund; or by a combination of these actions. Any facility registered in the Saskatchewan OBPS can apply to the Canadian Revenue Agency and receive an exemption from the federal fuel surcharge (carbon tax) on applicable fuel combustion. Crescent Point has large emitter and aggregate facilities registered in the Saskatchewan OBPS program.

On November 22, 2022, the Government of Saskatchewan announced amendments to the Saskatchewan OBPS to meet the requirements of the 2023-2030 national carbon pricing benchmark. Effective January 1, 2023, the regulated emissions under the Saskatchewan OBPS were expanded to include flaring and the emission intensity reduction was increased to 20%.

U.S. Greenhouse Gas Emissions Permitting and Regulation

In the United States, on December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA developed and implemented regulations that restrict GHG emissions under existing provisions of the federal CAA, including one rule that limits GHG emissions from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("**PSD**") and Title V permitting programs. This rule "tailored" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. However, based on a decision of the U.S. Supreme Court, only facilities already required to obtain PSD permits for other criteria pollutants must also reduce GHG emissions that exceed certain thresholds consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis.

In June 2014, the Supreme Court upheld most of the EPA's GHG permitting requirements, allowing the agency to regulate the emission of GHG from stationary sources already subject to the PSD and Title V requirements. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and, hence, under the Supreme Court's ruling, may also be subject to the installation of controls to capture GHG. For any equipment or installation so subject, we may have to incur increased compliance costs to capture related GHG emissions. In October 2016, the EPA proposed revisions to the rule applicable to GHGs for PSD and Title V permitting requirements. The proposed rule has not been finalized.

In addition, both houses of Congress have actively considered legislation to reduce GHG emissions and many states have already taken legal measures to reduce GHG emissions, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA issued regulations that limit GHG emissions including those associated with our operations which will require us to incur costs to inventory and reduce GHG emissions associated with our operations.

On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022 ("**IRA"**). The IRA imposes a fee of up to $1,500 per metric ton of methane emitted above specified thresholds from onshore petroleum and natural gas production facilities, natural gas processing facilities, natural gas transmission and compression facilities, and onshore petroleum and natural gas gathering and boosting facilities, among other facilities. The fees will apply to methane emissions after January 1, 2024. Congress may adopt additional significant legislation in the future to reduce emissions of GHGs.

On November 30, 2022, the U.S. Bureau of Land Management ("**BLM**") published a proposed rule that would regulate venting, flaring, and leaks of natural gas occurring during oil and gas production activities on federal and Indigenous leases. If finalized as proposed, the rule would limit gas that may be flared royalty-free during well completions, production testing, and emergencies; establish a monthly volume limit on royalty-free flaring due to pipeline capacity constraints, midstream processing failures, or other similar events; require vapor recovery systems on oil tanks; require operators to maintain leak detection and repair programs; prohibit the use of certain natural-gas-activated pneumatic controllers and pneumatic diaphragm pumps; and require operators to submit waste minimization plans with applications for permits to drill, among other requirements.

Although the U.S. had withdrawn from the Paris Agreement, the Biden administration has issued executive orders recommitting the U.S. to the Paris Agreement and calling for the federal government to begin formulating the U.S.' nationally determined emissions reduction goal under the Paris Agreement. In April 2021, President Biden announced that the United States would aim to cut its greenhouse gas emissions 50 to 52 percent below 2005 levels by 2030. This commitment will be part of the United States' "nationally determined contribution", or NDC, to the Paris Climate Agreement. The NDC will commit the United States to a voluntary GHG emission reduction target and outline domestic climate mitigation measures to achieve that target. With the U.S. recommitting to the Paris Agreement, additional executive orders may be issued or federal legislation or regulatory initiatives may be adopted to achieve the Paris Agreement's goals.

On January 27, 2021, the Biden administration also issued an executive order that commits to substantial action on climate change, calling for, among other things, suspending the issuance of new leases for oil and gas development on federal lands, pending completion of a review of leasing and permitting practices and expanding on the Acting Secretary of the U.S. Department of the Interior's January 20, 2020, order, effective immediately, that suspended new oil and gas leases and drilling permits on federal lands and waters for a period of 60 days. The executive order also called for the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and an increased emphasis on climate-related risks across government agencies and economic sectors. In June 2021, a federal judge in Louisiana preliminarily enjoined the administration's suspension of oil and gas leasing on federal lands and waters. In August 2021, the administration appealed that ruling to the Fifth Circuit, and on August 17, 2022, the Fifth Circuit vacated and remanded the Louisiana court's preliminary injunction, holding that the order lacked specificity. The following day, however, the Louisiana court permanently enjoined the suspension. In 2022, the DOI resumed oil and gas leasing on federal onshore public lands on a limited basis, which is still pending. The Biden administration could also impose more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against fossil fuel producer companies in state or federal court, alleging that such companies created public nuisances by producing fuels that contributed to global warming effects.

The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic United States regulations. In addition to the federal legislative and regulatory changes, in several U.S. states, the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to oil and gas facilities.

Methane Policy

On June 29, 2016, Canada joined the United States and Mexico in agreeing to reduce methane emissions from the oil and gas sector by up to 45% by 2025 from 2014 levels by developing and implementing federal regulations for both existing and new sources of venting and fugitive methane emissions. Previously, on March 10, 2016, Canada and the United States committed to take action on methane emissions through federal regulations as expeditiously as possible. The United States has since cancelled their participation in this initiative.

On January 1, 2020, the Canadian federal government implemented the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*.

The federal regulations that apply to methane in the upstream oil and gas sector aim to control methane emissions and also reduce the amount of volatile organic compounds released into the air. These regulations apply generally to facilities that handle significant volumes of gas (facilities that produce or receive a combined volume of 60,000 m^3 of hydrocarbon gas or greater annually in any of the past five years). The regulations outline regulatory requirements for fugitive equipment leaks, venting from well completions, and compressors, which came into force on January 1, 2020, and requirements for facility production venting restrictions and venting limits for pneumatic equipment, which come into force on January 1, 2023.

Operators of upstream oil and gas facilities are required to: implement a leak detection and repair program to stop natural gas leaks three times per year on facilities that produce or receive a combined volume of 60,000 m^3 of hydrocarbon gas or greater annually; complete annual measurements of emissions from natural gas compressor vents to ensure emissions are under the applicable limit; and eliminate venting from well completions involving hydraulic fracturing.

Beginning in 2023, operators of upstream oil and gas facilities will be required to: meet a venting limit of 15,000 m^3 of gas per year at facilities that produce and/or receive more than 60,000 m^3 of gas per year, and limit venting from pneumatic devices to a maximum threshold.

All upstream oil and gas facilities to which the federal regulations apply are required to register and to keep records in order to demonstrate compliance with the proposed regulations. Facility operators are also required to submit reports at the request of the federal Minister of Environment.

On October 11, 2021, the Canadian federal government announced its support for the Global Methane Pledge, which aims to reduce global methane emissions by 30 percent below 2020 levels by 2030. In support of the Global Methane Pledge, Canada announced its commitment to developing a plan to reduce methane emissions across the broader Canadian economy and to reducing oil and gas methane emissions by at least 75 percent below 2012 levels by 2030, and that these goals will be achieved through an approach that will include regulation.

In September 2022, the Government of Canada released Canada's Methane Strategy with the aim of reducing domestic methane emissions, including a new target of reducing absolute methane emissions from the oil and gas sector by 75% by 2030 relative to 2012. In November 2022, the Government of Canada released a Proposed Regulatory Framework for Reducing Oil and Gas Methane Emissions to Achieve 2030 Target. The proposed changes will expand the scope of the existing regulations to apply to a wider set of sources, including all facilities handling natural gas, increasing the scope and frequency of inspection programs, requiring certain non-emitting equipment when feasible, prohibiting flaring at oil sites, limiting venting of methane and requiring fugitive methane emissions management plans.

Currently the federal regulations do not apply in provinces which the federal government deems to have equivalent methane reduction regulations. Alberta, Saskatchewan and British Columbia have each reached equivalency agreements with the federal government and currently operators in these provinces are subject to only the provincial methane reduction requirements.

In Alberta, new design specifications have been put in place by the AER for oil and gas wells, pipelines and facilities as well as standards for key equipment and operational best practices. Fugitive emission standards are also included in the regulatory requirements and will raise current standards for performance, monitoring, measurement and reporting. The AER has published directives requiring methane emission reductions commencing January 1, 2020.

On January 1, 2019, the Government of Saskatchewan brought into force *The Oil and Gas Emissions Management Regulations* to reduce methane emissions from upstream oil and gas companies with emissions of more than 50,000 tonnes of GHGs per year from oil facilities. Every company subject to the regulation must ensure GHG emissions from flaring and venting are below provincial limits or pay an administrative penalty if they fail to do so.

Crescent Point's operations are subject to costs being incurred to comply with carbon taxes, GHG emission reduction requirements, including methane emission reductions, and to preform necessary monitoring, measurement, verification and reporting of GHG emissions.

Crescent Point anticipates current and future environmental legislation will require reductions in emissions from its operations and result in increased capital and operational expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition and results of operations.

We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures as a result of the increasingly stringent laws relating to the protection of the environment. Our internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding.

Abandonment and Reclamation Costs

As at December 31, 2022, Crescent Point owned approximately 13,609 gross (11,367 net) producing and non-producing, abandoned wells for which abandonment and/or reclamation costs are expected to be incurred. During 2022, Crescent Point spent approximately $43.1 million on well abandonment and environmental reclamation activities, of which $23.0 million was received from government grant programs. In 2023, Crescent Point expects to carry out abandonment and reclamation operations that will total approximately $41.6 million, including amounts expected to be received from government programs. Crescent Point has estimated the net present value (discounted at approximately 3.28% per annum) of its total decommissioning liability (wells and facilities) to be approximately $703.9 million as at December 31, 2022, including liabilities associated with assets held for sale, based on estimated undiscounted and uninflated cash flows of approximately $931.8 million.

On July 30, 2020, the Government of Alberta announced a new liability management program that overhauls and modernizes the previous liability management program, known as the Liability Management Ratio (**"LMR"**) which uses a licensee's ratio of deemed asset value to deemed liability value to determine the risk that the licensee poses to the Orphan Well Association and to determine if a security deposit is required to mitigate that risk. The LMR was replaced by Directive 088: Licensee Life-Cycle Management ("**LLCM**"), which directive was released and became effective on December 1, 2021. Unlike the LMR, which measures two metrics to determine a licensee's risk, the LLCM assesses more than 30 additional metrics, such as the licensee's financial capability, previous closure activity, operational performance and regulatory compliance. Additionally, the new liability framework includes an Inactive Inventory Reduction Program which introduced annual mandatory liability reduction spending targets for each licensee. The new framework also includes the development of a program to address legacy sites that were abandoned, remediated or reclaimed before current requirements were introduced. In September 2022, the AER introduced the Closure Nomination Program as part of LLCM. This program allows for specific, direct stakeholders to nominate inactive sites for abandonment and/or reclamation.

Like the Alberta Government, the Government of Saskatchewan also announced enhancements to its Liability Management Program framework in 2020. This framework includes using licensee-specific data to better reflect the actual deemed asset and liability values, which is expected to improve the accuracy of License Liability Ratings; an Inactive Liability Reduction Program that requires an annual spending target on closure activities; completing the Proportional Risk Transfer model that will assess security deposit requirements for license transfers with a high amount of inactive infrastructure; and addressing regulatory gaps related to new entrants and the acceptable forms of security deposits. To support these new initiatives, the Government of Saskatchewan has enacted *The Financial Security and Site Closure Regulation*, which came into force on January 1, 2023.

Health, Safety and Environment

The health and safety of employees, contractors, visitors and the public, as well as the protection of the environment, is of the utmost importance to Crescent Point. The Corporation endeavors to conduct its operations in a manner that will minimize both adverse environmental effects and consequences of emergency situations by:

- Complying with all applicable government regulations and standards;
- Operating in a manner consistent with industry codes, practices and guidelines;
- Ensuring prompt and effective response and repair to emergency situations and environmental incidents;
- Providing training to ensure compliance with Crescent Point's Operations Management System;
- Careful planning, good judgment and prudent monitoring of the Corporation's activities;
- Communicating openly with all stakeholders regarding our activities; and
- Amending Crescent Point's policies and procedures, as may be required from time to time.

Crescent Point believes that it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. Crescent Point's practice is to do all that it reasonably can to ensure that it remains in material compliance with applicable environmental protection legislation. Crescent Point also believes that it is reasonably likely that the trend towards stricter standards in environmental regulation will continue. Crescent Point is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. Crescent Point anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, the development or exploration activities, or otherwise adversely affect Crescent Point's financial condition, capital expenditures, results of operations, competitive position or prospects.

RISK FACTORS

Each of the risks described below should be carefully considered, together with all of the other information contained herein, before making an investment decision with respect to our Common Shares. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you could lose all or part of your investment.

Risks Relating to Our Business

Our estimated Proved and Proved plus Probable reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

The reserve and recovery information contained in the Crescent Point Reserve Report are only estimates and the actual production and ultimate reserves from our properties may be greater or less than the estimates prepared by McDaniel. Ultimately, actual reserves attributable to our properties will vary from estimates, and those variations may be material. The reserve figures contained herein are only estimates. The estimation of reserves is an inherently complex process requiring significant judgment. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- future commodity prices, production and development costs, royalties and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- success of future development activities;
- marketability of production;
- availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities;
- effects of government regulation; and
- other government levies that may be imposed over the producing life of reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the relevant evaluations were prepared. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change. See "*Special Notes to Reader*". Many of these factors are subject to change and are beyond our control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates and such variations may affect the market price of our Common Shares and return of capital (which, for purposes of this AIF, includes dividends and share repurchases) to Shareholders.

The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems.

Our business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and rail loading facilities and railcars. Canadian federal and provincial, as well as U.S. federal, state and local regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, changes in supply and demand and changes in pipeline ownership or operation could adversely affect our ability to produce or market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which may affect the market price of our Common Shares and reduce our return of capital to our Shareholders.

Our future performance depends on our ability to acquire additional natural gas and oil reserves that are economically recoverable.

If we are unable to acquire additional reserves, the value of our Common Shares and our return of capital to Shareholders may decline. We add to our oil and natural gas reserves primarily through development, exploitation and acquisitions including those with large resource potential. As a result, future oil and natural gas reserves are highly dependent on our success in exploiting existing properties and acquiring additional reserves. We cannot guarantee that we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and, as a consequence, either production from, or the average reserve life of, our properties may decline. Either decline may result in a reduction in the value of our Common Shares and in a reduction in cash available for return of capital to Shareholders.

The properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the acquired properties or obtain protection from sellers against such liabilities.

The properties we acquire may not produce as expected, may be in an unexpected condition and we may be subject to increased costs and liabilities, including environmental liabilities. Although we review properties prior to acquisition in a manner consistent with industry practices, such reviews are not always capable of identifying all potential adverse conditions. Furthermore, we may not be able to subject the preparation of reserve estimates for acquired properties to the same internal controls we have for the preparation of reserve estimates for our existing properties. Generally, it is not feasible to review in depth every individual property involved in each acquisition. We focus our review efforts on the higher-value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties and preparation of reserve reports in accordance with our internal controls may not necessarily reveal existing or potential problems or permit us to become sufficiently familiar with the properties to fully assess their condition, any deficiencies, and development potential.

Failure to realize anticipated benefits of prior acquisitions and dispositions may have a material adverse effect on our business.

The Corporation has completed a number of acquisitions and dispositions in order to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits, including, among other things, potential cost savings. In order to achieve the benefits of these and future acquisitions, the Corporation is dependent upon its ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Corporation. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of such prior acquisitions. Dispositions may fail to provide anticipated benefits as the employment of capital received from any such dispositions will be subject to the risks the Corporation faces. Such capital may fail to deliver a return commensurate or greater than the return formerly garnered from the disposed assets.

Increases in costs could adversely affect our business, financial condition and results of operations.

An increase in costs could have a material adverse effect on our results of operations and financial condition and, therefore, could reduce our ability to pay down debt, reduce dividends to Shareholders as well as affect the market price of the Common Shares.

Current and future inflationary effects may be driven by, among other things, supply chain disruptions and governmental stimulus or fiscal policies, and geopolitical instability, including the ongoing conflict between the Ukraine and Russia. Continuing increases in inflation could increase our costs of labor and other costs related to

our business, which could have an adverse impact on our business, financial position, results of operations and cash flows.

Higher operating and capital costs for our underlying properties will directly decrease the amount of cash flow received by the Corporation and, therefore, may reduce return of capital to our Shareholders.

The COVID-19 pandemic has adversely affected and could continue to adversely affect the Corporation's financial condition, operations and results from operations.

The COVID-19 pandemic, and initial actions taken in response, resulted in a significant contraction in the global economy. This caused a period of unprecedented disruption in the oil and gas industry and negatively impacted the demand for, and pricing of, energy products, including crude oil, NGLs and natural gas produced by the Corporation. A consequence of this disruption is that the oil and gas industry experienced a period of market contraction. Furthermore, the oil and gas industry experienced an increased risk of counterparty bankruptcy and insolvency. Although the pricing of energy products has returned to historical norms, volatility persists and disruptions to the oil and gas industry related to the pandemic could be severe.

In response to the COVID-19 pandemic, the Corporation implemented additional health and safety protocols within its Calgary office and field operations and continues to make adjustments to its health and safety protocols as required.

There are many variables and uncertainties that still remain regarding COVID-19, as well as its continued impact on the economic environment, including the duration of any further disruption to the oil and gas industry. During the COVID-19 pandemic, inflation has been driven by many factors, including disruptions to local and global supply chain and transportation services. Additionally, COVID-19 and its variants have the potential to directly affect the health of our employees. Inflation, disruptions to supply chain and transportation services and employee health have the potential to disrupt or impact the Corporation’s operations, projects and financial condition. The extent of the impact of COVID-19 on our operational and financial performance will depend on future developments, including the reemergence of widespread COVID-19 infections, COVID-19 variants, the pandemic's severity, government actions to contain the disease or mitigate its impact and the effectiveness of treatments and vaccines, all of which are highly uncertain and cannot be predicted with certainty at this time. Although government response measures to COVID-19 have generally relaxed, the ultimate impact of the pandemic is uncertain and subject to change. Other risks disclosed in this Annual Information Form may be heightened and there may also be effects that are not currently known.

The conflict in Ukraine and related price volatility and geopolitical instability could negatively impact our business.

In late February 2022, Russia launched significant military action against Ukraine. The conflict has caused, and could intensify, volatility in natural gas, oil and NGL prices, and the extent and duration of the military action, sanctions and resulting market disruptions could be significant and could potentially have a substantial negative impact on the global economy and/or our business for an unknown period of time. There is evidence that the increase in crude oil prices during the calendar year 2022 was partially due to the impact of the conflict between Russia and Ukraine on the global commodity and financial markets, and in response to economic and trade sanctions that certain countries have imposed on Russia. Any such volatility and disruptions may also magnify the impact of other risks described in this "Risk Factors" section.

The operation of a portion of our properties is largely dependent on the ability of third party operators.

Some of our properties are not operated by us and, therefore, results of operations may be adversely affected by the failure of third-party operators, which could affect the market price of our Common Shares and return of capital to Shareholders.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of those properties. At December 31, 2022, approximately 5% of our daily production was from properties operated by third parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, our revenue may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

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

Delays in business operations could adversely affect our income and financial condition.

Delays in business operations could adversely affect return of capital to Shareholders, our income, our financial condition and the market price of our Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline, railcar, trucking or refinery capacity;
- extreme weather events, including severe cold, wildfires and floods, which may damage or destroy infrastructure;
- blowouts or other accidents;
- public health crises, epidemics or pandemics, including the effects of, and response to, COVID-19;
- blockades and social unrest;
- accounting delays;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties;
- the establishment by the operator of reserves for these expenses; or
- delays in receiving government approvals and licenses.

Any of these or other delays in our business operations could reduce our income, the amount of cash available for return of capital to Shareholders in a given period, our financial condition and could expose us to additional third party credit risks.

Failure of third parties to meet their contractual obligations to us may have a material adverse effect on our financial condition.

Although the Corporation monitors the credit worthiness of third parties it contracts with and manages its exposures through a formal Risk Management and Counterparty Credit Policy, there can be no assurance that the Corporation will not experience a loss for non-performance by any counterparty with whom it has a commercial relationship. Such events may have material adverse consequences on the business of the Corporation and may limit the timing or amount of return of capital to Shareholders and could affect the market price of our Common Shares.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, ability to return capital to shareholders, results of operations, cash flows and business prospects.

We may, from time to time, finance a significant portion of our operations through debt. Our indebtedness may limit the timing or amount of capital returns to Shareholders, and could affect the market price of our Common Shares and our return of capital to Shareholders.

The payments of interest and principal, and other costs, expenses and disbursements to our lenders reduces amounts available for return to Shareholders. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flow required to be applied to the debt before payment of any amounts to the Shareholders. The agreements governing our long-term debt provide that, if we are in default or fail to comply with certain covenants, we must repay the indebtedness at an accelerated rate, and the ability to return capital to Shareholders may be restricted. Significant reductions to cash flow or increases in drawn amounts under the Credit Facilities may result in the Corporation breaching its debt covenants under the agreements governing its long-term debt. 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 long-term debt counterparties. Failure to comply with debt covenants or negotiate relief may result in its indebtedness under the Credit Facilities or Senior Guaranteed Notes becoming immediately due and payable, which may have a material adverse effect on the Corporation's operations and financial condition.

Increased costs of capital could adversely affect our business.

Our business and operating results could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows and place us at a competitive disadvantage. Disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could have a material adverse effect on the Corporation's operations and financial condition.

Our existing credit facilities and any replacement credit facilities may not provide sufficient liquidity.

Our current credit facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing credit facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. The interest charged on our Syndicated Credit Facility is calculated based on a sliding scale ratio of the Corporation's senior debt to adjusted EBITDA ratio. Repayment of all outstanding amounts under the Syndicated Credit Facility may be demanded on relatively short notice if an event of default occurs and is continuing. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and return of capital to Shareholders may be materially reduced.

Dividends on the Corporation's Common Shares and Common Share repurchases are variable.

Dividends may be reduced or eliminated in the sole discretion of the Board of Directors. For example, dividends may be reduced or eliminated during periods in which we make capital expenditures or debt repayments using cash flow, which could also affect the market price of our Common Shares. To the extent that we use cash flow to finance acquisitions, development costs and other significant expenditures, the net cash flow the Corporation receives that is available for dividends to Shareholders, or to repurchase Common Shares will be reduced. Furthermore, the availability of net cash flow is dependent upon commodity prices which are variable. Hence, the timing and amount of capital expenditures and the variability of commodity prices, may affect the amount of net cash flow received by the Corporation and, as a consequence, the amount of cash available to distribute to Shareholders or to repurchase Common Shares. Therefore, dividends or share buybacks may be reduced, or even eliminated, at times when significant capital or other expenditures are made, or when commodity prices vary.

The Board of Directors has the discretion to determine the extent to which cash flow from Crescent Point will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the Credit Facilities. As a consequence, the amount of funds used to pay debt service charges or reduce debt will reduce the amount of cash available for dividends to Shareholders or to repurchase Common Shares during those periods in which funds are so retained.

We have been historically reliant on external sources of capital, which may dilute Shareholders' ownership interests.

There may be future dilution to our Shareholders. One of our objectives is to continually add to our reserves through acquisitions and through development. Since we pay a dividend, our success in growth from acquisitions and development may, in part, depend on our ability to raise capital from time to time by selling additional Common Shares. Shareholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common Shares issued to acquire those assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to effect acquisitions.

Indigenous claims could have an adverse effect on us and our operations.

The economic impact on us of claims of indigenous title or rights is unknown. Indigenous people have claimed indigenous title and rights to a substantial portion of western Canada and the U.S. We are unable to assess the effect, if any, that any such claim would have on our business and operations. Protests that affect transportation and other infrastructure in Canada, may have a negative impact on the Corporation's ability to sell its products.

Hedging limits participation in commodity price increases and increases counterparty credit risk exposure.

We periodically enter into hedging activities with respect to a portion of our production to manage our exposure to oil and gas price volatility. To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from fully realizing the benefits of commodity price increases above the prices established by our hedging contracts. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the contract counterparties fail to perform under the contracts.

We may incur losses as a result of title defects in the properties in which we invest.

Unforeseen title defects may result in a loss of entitlement to production and reserves. Although we conduct title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat our title to the purchased assets. If such a defect were to occur, our entitlement to the production from such purchased assets could be jeopardized and, as a result, return of capital to Shareholders may be reduced.

Our information assets and critical infrastructure may be subject to cyber security risks.

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

Crescent Point relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data. In addition, information systems could be damaged or interrupted by natural disasters, *force majeure* events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on Crescent Point's business, financial condition, results of operations and cash flows.

We depend upon our management team and our operations require us to attract and retain experienced technical personnel.

Shareholders are entirely dependent on our management with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves and the management and administration of all matters relating to our oil and natural gas properties. The loss of the services of key individuals who currently comprise the management team could have a detrimental effect on the Corporation. Additionally, COVID-19 may disrupt the ability of our management team to provide services.

We operate only in western Canada and the United States and expansion outside of these areas may increase our risk exposure.

If we expand our operations beyond oil and natural gas production in western Canada, North Dakota and Montana, we may face new challenges and risks. If we were to be unsuccessful in managing these challenges and risks, our results of operations and financial condition could be adversely affected, which could affect the market price of our Common Shares and return of capital to Shareholders.

Our operations and expertise are currently deployed on conventional oil and gas production and development in the Western Canadian Sedimentary Basin and in North Dakota and Montana. In the future, we may acquire oil and gas properties outside this geographic area. In addition, we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present challenges and risks that we have not faced in the past. If we do not manage these challenges and risks successfully, our results of operations and financial condition could be adversely affected.

We may be the subject of litigation.

From time to time, the Corporation may be the subject of litigation. Claims under such litigation may be material. The types of claims the Corporation may face include, without limitation, claims for breach of contract, environmental damage, negligence, product liability, tax, patent infringement and employment matters. The outcome of any such litigation is not certain, but may materially impact Crescent Point's financial condition or results of operations. Crescent Point may also be subject to adverse publicity related to such claims, regardless whether Crescent Point is ultimately found responsible. In addition, the Corporation may be required to incur significant expenses or devote significant resources defending any such litigation.

Risks Relating to the Oil and Gas Industry

Oil and natural gas prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Lower commodity prices may reduce the amount of oil and natural gas that we can produce economically. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results and could result in impairment charges.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include but are not limited to the following:

- the levels and location of oil and natural gas supply and demand and expectations regarding supply and demand, both domestically and abroad;
- the level of consumer product demand;
- extreme weather events, such as severe cold, wildfires and floods;
- political conditions, social unrest, sanctions, hostilities or war in, or relating to, oil and natural gas producing regions, including the Middle East, Africa, Eastern Europe (including the conflict between Ukraine and Russia) and South America;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- the price level and quantity of foreign imports;
- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for oil and natural gas;
- blockades of transportation infrastructure and civil unrest;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- conservation and environmental protection efforts;
- the price, availability and acceptance of alternative energy sources;
- technological advances affecting energy usage and consumption and energy supply;
- speculation by investors in oil and natural gas;
- public health crises, epidemics or pandemics, including the impacts of and response to COVID-19;
- weather conditions;
- variations between product prices at sales points and applicable index prices; and
- overall domestic and worldwide economic conditions, including the value of the U.S. dollar relative to Canadian and other major currencies.

These factors and the volatile nature of the energy markets make it extremely difficult to predict with any certainty the future prices of crude oil and natural gas. If crude oil and natural gas prices remain significantly depressed for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital, meet our financial obligations or provide return of capital to shareholders through dividends or share repurchases.

Variations in interest rates, foreign exchange rates, and inflation could adversely affect our financial condition.

There is a risk that interest rates will continue to increase in response to inflation in Canada and the United States. An increase in interest rates could result in a significant increase in the amount we pay to service debt, while rising inflation could cause us to incur additional expense and, either or both, could have an adverse effect on our financial condition, results of operations and future growth, potentially resulting in a decrease in a decrease in the return of capital to Shareholders and/or the market price of the Common Shares.

Fluctuations in foreign currency exchange rates could adversely affect our business, and could affect the market price of our Common Shares and return of capital to Shareholders. The price that we receive for a majority of our oil and natural gas is based on U.S. dollar denominated benchmarks and, therefore, the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the U.S. dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given U.S. dollar price. Conversely, a material decease in Canadian versus U.S. dollar values would reduce the Corporation's ability to develop the U.S. asset base. Each of these situations may negatively impact future dividends and the future value of the Corporation's reserves as determined by independent evaluators. We could be subject to unfavorable exchange rate changes to the extent of our investment in U.S. subsidiaries and to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

Competition in the oil and gas industry is intense, which may adversely affect our ability to compete.

The oil and natural gas industry is highly competitive. We compete for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than we do. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of our competitors may have greater and more diverse competitive resources to draw on than we do. Given the highly competitive nature of the oil and natural gas industry, this could adversely affect the market price of our Common Shares and return of capital to Shareholders.

Risks associated with the production, gathering, transportation and sale of oil and natural gas could adversely affect net income and cash flows. We may not be insured against all of the operating risks to which our business is exposed.

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance. Our operations are subject to all of the risks associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells, and the production and transportation of oil and natural gas. These risks include encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires, spills and explosions. A number of these risks could result in personal injury, loss of life, or environmental and other damage to our property or the property of others and reputational loss. We cannot fully protect against all of these risks, nor are all of these risks insurable. We may become liable for damages arising from these events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for payment of dividends to Shareholders. Additionally, the insurance market changes over time and, in the future, we may not be able to purchase insurance for all of the risks that we are currently able to insure against.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Crescent Point is subject to extensive and complex regulations and laws enforced by various regulatory agencies. These regulatory agencies include, in Canada, the AER, the Alberta EPA, the British Columbia Energy Regulator, the British Columbia Ministry of Environment and Climate Change Strategy, the SMER, the Manitoba Ministry of Climate, Environment and Parks, Environment and Climate Change Canada, Health Canada, Transport Canada and the Department of Fisheries and Oceans , CER, and, in the U.S., the EPA, the BLM, U.S. Bureau of Indian Affairs and the NDIC. Additionally, the development or implementation of changes to land use activities, such as regional or subregional planning, may effect how we are able to use certain lands for oil and gas development. Crescent Point is also subject to regulation by other federal, provincial, state and local agencies. Regulations affect almost every aspect of Crescent Point's business and limit its ability to make and implement independent management decisions, including about business combinations, disposing of operating assets and engaging in transactions between Crescent Point and its affiliates.

Under these laws and regulations, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our financial condition and results of operations.

Regulations and laws are subject to ongoing policy initiatives, and Crescent Point cannot predict the future course of regulations or legislation and their respective ultimate effects. Such changes could materially impact Crescent Point's business, financial position and results of operations.

For further discussion about the effect of environmental laws and regulations, see below "*Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations*".

Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations.

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that Crescent Point may be in non-compliance with an environmental law, regulation, permit, license or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose Crescent Point to fines or penalties, suspension or revocation of regulatory permits, third party liabilities or to the requirement to remediate or carry out other actions, the costs of which could be material. The operational hazards associated with possible blowouts, accidents, oil spills, gas leaks, fires, explosions or other damage to a well, pipeline or facility may require Crescent Point to incur costs and delays to undertake corrective actions, and could result in penalties and fines and suspension or revocation of regulatory approvals or environmental or other damage for which Crescent Point could be liable. Oil and gas operations are also subject to specific operational risks which may have a material operational and financial impact on Crescent Point should they occur, such as drilling into unexpected formations or unexpected pressures, premature decline of reservoirs and water invasion into producing formations.

Crescent Point may also be subject to associated liabilities resulting from lawsuits alleging property damage or personal injury brought by private litigants related to the operation of Crescent Point's facilities or the land on which such facilities are located, regardless of whether Crescent Point leases or owns the facility, and regardless of whether such environmental conditions were created by Crescent Point, a prior owner or tenant, a third party or a neighbouring facility whose operations may have affected Crescent Point's facility or land. Such liabilities could have a material adverse effect on Crescent Point's business, financial position, operations, assets or future prospects.

Crescent Point also faces uncertainties related to future environmental laws and regulations affecting its business and operations. Existing environmental laws and regulations may be revised or interpreted more strictly, and new laws or regulations may be adopted or become applicable to Crescent Point, which may result in increased compliance costs or additional operating restrictions, each of which could reduce Crescent Point's earnings and adversely affect Crescent Point's business, financial position, operations, assets or future prospects. For example, if the Corporation did not qualify in 2022 for an exemption under the TIERS and OBPS programs in Alberta and Saskatchewan, respectively, the additional carbon compliance costs to the Corporation in Canada would have been, approximately, $13.7 million in 2022, which amount is calculated based on Scope 1 fuel combustion at the applicable 2022 carbon pricing rate.

Compliance with environmental laws and regulations could materially increase our costs. We may incur substantial capital and operating costs to comply with increasingly complex laws covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with future federal GHG emissions reduction requirements or other GHG emissions regulations. See below "*Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for oil and gas that we produce*".

Although we record a provision in our consolidated financial statements relating to our estimated future abandonment and reclamation obligations, we cannot guarantee that we will be able to satisfy our actual future abandonment and reclamation obligations. In addition, estimates of the costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. Although the Corporation maintains insurance consistent with prudent industry practice, we are not fully insured against certain environmental risks, including the impacts of climate change, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms.

Accordingly, our 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. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to Crescent Point. Any site remediation, reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of our reclamation budget and, if required, out of cash flow and, therefore, will reduce the amounts available for return of capital to Shareholders. Should we be unable to fully fund the cost of remedying an environmental problem, we might be required to suspend or terminate certain operations or enter into interim compliance measures pending completion of the required remedy.

Numerous governmental authorities, such as the EPA, and analogous state agencies, including in North Dakota and Montana, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of Crescent Point's operations.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for oil and gas that we produce.

Complying with climate change legislation and regulations has increased operating costs as we pay fuel charges imposed by such legislation and have undertaken initiatives to reduce GHG emissions. Additionally, complying with methane reduction regulations applicable to our business requires Crescent Point to incur additional operating costs in order to achieve compliance.

Changes to federal legislation, as well as legislation in British Columbia, Alberta and Saskatchewan require the restriction or reduction of GHG emissions or emissions intensity from our current and future operations and facilities, which may lead to increased operational costs associated with emission reductions, payments to technology funds, payments of carbon levies, the purchase and retirement of emission reductions or offset credits, or a combination of such actions. The required GHG reductions may not be technically or economically feasible for our operations and the failure to meet such emission reduction or emission intensity reduction requirements or other compliance mechanisms may materially adversely affect our business and result in fines, penalties and the suspension of some operations. Furthermore, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other compliance methods of reducing emissions or emission intensity to levels required in the future may significantly increase our operating costs or reduce output. Emission reductions or offset credits may not be available on an economic basis. Additionally, changes in technology could decrease the demand for our products.

The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic United States regulations. However, we may face increased and material costs as a result of GHG regulation in the U.S. Moreover, many experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in precipitation and extreme weather events, including severe cold, wildfires and floods, which can result in damage to or destruction of infrastructure, facilities and equipment. In addition, warmer winters in some regions as a result of climate change could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are realized due to climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

We may be unable to meet emissions targets.

We have set internal emissions reduction targets with respect to GHG emissions. There are substantial costs and operational changes required to meet such targets, and as such, we may be unable to finance the required changes to meet our emissions targets due to lack of capital for a variety of reasons, many of which are beyond our control.

Additionally, we may be unable to adequately alter our operations in such a way as to meet our emissions targets by the stated dates or at all.

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

The market price of our Common Shares is sensitive to a variety of market-based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates and the comparability of the Common Shares to other securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Federal, provincial, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Some of Crescent Point's operations use hydraulic fracturing, which involves the high pressure injection of fluids and sand down a well to fracture the reservoir and thereby stimulate the increased flow of oil or gas into the well bore. Hydraulic fracturing has been the subject of greater regulatory and public scrutiny and regulation in certain jurisdictions of the world, including some of the areas in which Crescent Point operates. In a limited number of areas, hydraulic fracturing has been banned pending public and scientific reviews or is subject to moratoria while regulators study the practice. Additionally, hydraulic fracturing has been found to induce seismicity, and the AER has developed monitoring and reporting requirements that companies must follow in certain areas of Alberta, and in certain cases, the AER may require that operations resulting in increased seismic activity be suspended and not resumed without AER approval. We may be required to expend additional costs to comply with future regulatory requirements with respect to hydraulic fracturing or, in the future, be unable to carry out hydraulic fracturing operations, thereby lessening the volume of oil and gas we could otherwise produce and this could have a material operational and financial impact on Crescent Point and adversely affect the market price of our Common Shares and dividends to Shareholders.

Our business and financial performance may be adversely affected by subsequent unavailability and unfavorable terms of water licenses.

Crescent Point utilizes fresh water in certain operations, including hydraulic fracturing operations, which water is obtained under licenses issued within each respective jurisdiction's regulations. If water use fees increase or a change under these licenses reduces the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licenses to withdraw water will not be rescinded, that additional conditions will not be added to these licenses or that the water licensed will be available. There is no assurance that if we require licenses or amendments to existing licenses, that these licenses or amendments will be granted on favorable terms. This may adversely affect our business, including the ability to operate our assets and execute development plans.

The Corporation's risk and/or cost of borrowing may be adversely affected by the uncertainty resulting from the Orphan Well Association v Grant Thornton Ltd. court decision.

On January 31, 2019, the Supreme Court of Canada released its decision in *Orphan Well Association v Grant Thornton Ltd.* (the "**Redwater decision**") overturning earlier decisions of the Alberta courts to hold that receivers and trustees can no longer avoid the AER legislated authority to: impose abandonment orders against licensees, or require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. As a result, any financial resources of a bankrupt licensee in Alberta may first be used to satisfy outstanding abandonment and reclamation obligations in respect of its unproductive assets. Remaining amounts, if any, will then satisfy the claims of secured creditors in accordance with the *Bankruptcy and Insolvency Act*. As a result of the Redwater decision, the provincial regulation of environmental liabilities and associated decommissioning liability in the oil and gas industry is undergoing changes. The SMER announced that changes will be made to how it assesses the financial ability of operators/licensees to meet their abandonment, reclamation and other regulatory obligations and on December 1, 2021, the AER brought into force the new LLCM. The impact of any such regulatory measures by a provincial or federal government on the Corporation is uncertain at this time.

Additionally, some issuers have been required by lenders to include covenants with respect to the asset recovery obligations in the agreements that govern their borrowings (including credit facilities and other debt obligations) following the Redwater decision. To date, the Corporation has not been required by its lenders to include such provisions, however, there can be no certainty that the Corporation's lenders will not require such or other covenants and contractual terms, which in turn could cause the Corporation's risk and/or cost of borrowing to increase, possibly materially.

Safety requirements involving rail transportation may adversely affect us and our Shareholders.

In response to train derailments occurring in the United States and Canada in 2013, U.S. and Canadian regulators have implemented additional rules to address the safety risks of transporting crude oil by rail.

In Canada, amendments have been made to the *Transportation of Dangerous Goods Regulations* which adopt a new class of tank car for flammable liquid dangerous goods service and which require all new rail tank cars destined for flammable liquid service to be built to the new specifications. Certain older tank cars used to transport crude oil have been phased out. Further, shippers of crude oil by rail now must have in place an Emergency Response Assistance Plan approved by the Minister of Transportation in order to be able to provide assistance to responders in the event of an accident. Other amendments require the consigner of a shipment of crude oil by rail to properly classify the crude oil and to certify that the classification is correct. Additionally, Transport Canada has introduced requirements for railway companies to reduce the speed of trains carrying dangerous goods such as crude oil and to implement various other safe operating practices.

In the United States, the Department of Transportation finalized new regulations in May 2015 for the transportation of flammable liquids, which align with the standards adopted by Canada. The final rule creates a new, enhanced tank car standard and an accelerated retrofitting schedule for older tank cars. The rule requires enhanced braking systems on trains transporting flammable liquids, restricts operating speeds, requires a risk assessment-based routing analysis, and mandates procedures for more accurate classification of crude oil. On December 4, 2015, the *FAST Act* came into force, which among other things, established a mandatory phase-out schedule for older tank cars.

These regulations and the adoption of any other regulations that impact the testing or rail transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout Canada and the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders.

Changes in tax and other laws may adversely affect the trading price of our Common Shares and return of capital to Shareholders. Tax authorities having jurisdiction over the Corporation or the Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of Shareholders.

The oil and gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, the provinces, the United States, and the various states, all of which should be carefully considered by investors in the oil and gas industry. All of such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition or results of operations or prospects and our ability to return capital to Shareholders.

Royalty changes may adversely affect us.

Royalty frameworks, including rates and available incentive programs, may be reviewed and amended from time to time by the applicable federal, provincial, state or other governmental bodies or agencies having jurisdiction. In addition, the royalty rates applicable to the Corporation's production of hydrocarbons may be impacted by changes in market prices for hydrocarbons, production volumes, and capital and operating costs. An increase in royalty rates would reduce the Corporation's cash flow and earnings, and could make future capital investments, or the Corporation's operations, less economic.

We are affected by seasonal weather patterns.

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities, provincial and state transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors, unexpected weather patterns, wildfires and floods may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

We may be adversely affected by extreme weather events.

Extreme weather events are an unpredictable risk. Wildfires can be caused by lightning, high temperatures, or by human activity and can spread because of wind and are otherwise encouraged by hot dry conditions. Floods can be caused by a high level of precipitation in a short period of time. Severe cold can cause water to freeze and expand leading to a chance that pipes can burst and valves may break. Wildfires, floods and severe cold can cause damage to or destroy infrastructure including roads, rail lines, and power transmission lines, cause damage to facilities and equipment, cause operational difficulties and access restrictions, lead to reduced operations or a cessation of operations in affected areas, and can cause supply chain disruptions affecting both our ability to market oil and gas and our ability to obtain goods and services required for our operations. Extreme weather events could adversely affect our business and operations, however, due to the unpredictable nature of extreme weather events, it is not possible to determine how or to what extent our business or operations may be affected.

We may be subject to environmental non-governmental organization legal challenges.

Environmental non-governmental organizations have become more aggressive in pursuing legal challenges to oil and gas companies, drilling and pipeline projects. In turn, this could result in increased costs and additional operating restrictions or delays as well as the risks under "*Risks Relating to Our Business - We may be Subject to Litigation.*"

Investor sentiment towards fossil fuel development may not align with our business.

Investor sentiment towards fossil fuel development has been affected by a number of factors, including public perception, climate change, environmental impacts of operations, environmental damage resulting from accidental releases, responsibility for orphaned wells and Indigenous rights. As a result of these and other concerns, some institutional, retail and governmental investors have announced that they will no longer fund or invest in oil and natural gas, or are reducing their investments in the same. Some institutional investors are also requesting that issuers develop and implement robust social, environmental and governance policies and practices, which may be more stringent than those which Crescent Point already has in place. Changing investor sentiment can make capital harder to access or more expensive, and may also have an effect on the value of our assets. It is not expected that changing investor sentiment will affect our operations in a manner materially different than they would affect other oil and gas entities of similar size.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited.

Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States.

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties), however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, whereas, the SEC rules require that a trailing 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-month for each month within the 12-month period to the end of the reporting period, and uninflated (constant) costs be utilized. The SEC permits, but does not require, the disclosure of reserves based on forecast prices and costs.

Reserve information contained herein include estimates of Proved and Proved plus Probable reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only Proved reserves. The SEC permits, but does not require, the inclusion of estimates of Probable reserves in filings made with it by United States oil and gas companies. The SEC definitions of Proved reserves and Probable reserves are different than those in NI 51-101. As a consequence of the foregoing, our reserve estimates and production volumes in this AIF may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

Shareholders who are non-residents of Canada may be subject to additional taxation.

The Tax Act imposes a withholding tax at the rate of 25% on dividends paid by us to Shareholders who are non-residents of Canada, unless the rate is reduced under the provisions of a tax treaty between Canada and the non-resident Shareholder's jurisdiction of residence. These withholding tax rates may change from time to time. Where the non-resident Shareholder is a United States resident entitled to benefits under the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividend, the rate of Canadian withholding tax applicable to dividends is generally reduced to 15%. Shareholders who are non-residents of Canada are encouraged to consult with their tax advisors for more information concerning additional taxation that may be applicable to them.

Shareholders who are non-residents of Canada may be subject to foreign exchange risk.

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

DIVIDENDS AND SHARE REPURCHASES

The Corporation has established a dividend policy of paying regular dividends to Shareholders. An objective of the Corporation's dividend policy is to provide Shareholders with relatively stable and predictable dividends. An additional objective is to retain a portion of cash flow to fund ongoing development and optimization projects designed to enhance the sustainability of the Corporation's cash flow. Commencing in 2019, the Corporation moved to a quarterly dividend, paid on the first business day of each quarter. Dividends are paid to Shareholders of record on the 15th day of the month prior to the payment date.

Additionally, as part of its return of capital framework that targets the return of up to 50% of the Corporation's discretionary excess cash flow, the Corporation may declare special dividends. The first of such special dividends was paid on November 14, 2022, in the amount of $0.035 per Share.

The amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including the price of oil and gas, the prevailing economic and competitive environment, results of operations, debt and working capital levels, the taxability of Crescent Point, Crescent Point's ability to raise capital, the amount of capital expenditures and other conditions existing from time to time. There can be no guarantee that Crescent Point will maintain its dividend policy.

Although the Corporation strives to provide Shareholders with stable and predictable cash flows, the percentage of cash flow from operations paid to Shareholders may vary according to a number of factors, including, fluctuations in resources prices, exchange rates and production rates, reserves growth, the size of development drilling programs and the portion thereof funded from cash flow and the overall level of debt of the Corporation.

The agreements governing the Credit Facilities and Senior Guaranteed Notes provide that distributions to Shareholders and share repurchases are not permitted if the Corporation is in default under the agreements or the payment of such distribution would cause an event of default.

The following table sets forth the amount of cash dividends declared per Common Share by the Corporation for the periods indicated.

			Dividends per Common Share ($)
January 2020	–	December 2020	0.0175
January 2021	–	December 2021	0.0825
January 2022	–	December 2022	0.3600

Normal Course Issuer Bid

On March 9, 2021, Crescent Point commenced the 2021 NCIB to purchase, for cancellation, up to 26,462,509 Common Shares, representing 5% of the Corporation's public float as at February 26, 2021. The 2021 NCIB expired on March 8, 2022. A total of 8,602,500 Common Shares were purchased for cancellation under the 2021 NCIB.

On March 9, 2022, Crescent Point commenced the 2022 NCIB to purchase, for cancellation, up to 57,309,975 Common Shares, representing 10% of the Corporation's public float as at February 28, 2022. The 2022 NCIB is due to expire on March 8, 2023. In 2022, the Corporation purchased 25,561,600 Common Shares under the 2022 NCIB. As of February 20, 2023, the Corporation had purchased an additional 2,526,900 Common Shares under the 2022 NCIB in 2023.

The objective of the 2021 NCIB and the 2022 NCIB was to return capital to Shareholders in a way that is accretive to both Shareholders and the Corporation. Purchases of Common Shares under the 2022 NCIB may be made through the facilities of the TSX or the NYSE, alternative trading systems by means of open market transactions, or by such other means as may be permitted by the TSX and applicable securities laws.

MARKET FOR SECURITIES

The outstanding Common Shares are traded on the TSX and the NYSE under the trading symbol "CPG". The following tables set forth the price range and trading volume of the Common Shares as reported by the TSX and NYSE for the periods indicated.

TSX	High ($)	Low ($)	Volume (000's)
2022			
January	8.57	7.08	133,375
February	9.15	7.78	106,162
March	10.08	7.87	148,580
April	10.05	8.09	103,824
May	11.59	8.18	141,197
June	13.74	8.69	187,316
July	10.25	7.87	111,614
August	10.85	8.56	105,555
September	10.00	7.57	106,038
October	11.14	8.91	94,437
November	11.54	9.96	82,037
December	10.65	8.83	84,977
2023			
January	10.22	8.64	77,066
February 1 - 20	10.09	9.13	61,302

NYSE	High (US$)	Low (US$)	Volume (000's)
2022			
January	6.85	5.38	151,331
February	7.23	6.12	140,904
March	7.87	6.13	228,224
April	7.98	6.33	176,065
May	9.15	6.27	250,061
June	10.96	6.68	369,861
July	8.00	6.02	269,912
August	8.35	6.60	267,511
September	7.63	5.51	263,675
October	8.25	6.49	326,524
November	8.61	7.38	177,460
December	7.94	6.46	131,835
2023			
January	7.67	6.39	103,313
February 1 - 20	7.57	6.77	89,257

CONFLICTS OF INTEREST

Circumstances may arise where members of the Board of Directors or officers of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such Board members or officers will be provided to the Corporation. In accordance with the ABCA, a director or officer who is a party to a material contract or proposed material contract with the Corporation or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Corporation shall disclose to the Corporation the nature and extent of the director's or officer's interest. In addition, a director shall not vote on any resolution to approve a contract of the nature described except in limited circumstances. Management of the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation or a subsidiary of the Corporation and a director or officer of the Corporation or any other subsidiary of the Corporation.

LEGAL PROCEEDINGS

There are no outstanding legal proceedings material to the Corporation to which we are a party or in respect of which any of our properties are subject, nor are any such proceedings known to be contemplated.

AUDIT COMMITTEE

General

The Corporation has established an Audit Committee (the "**Audit Committee**") comprised of four members: Mike Jackson (Chair), Ted Goldthorpe, Francois Langlois and Mindy Wight each of whom is considered "independent" and "financially literate" within the meaning of National Instrument 52-110 – Audit Committees.

Mandate of the Audit Committee

The mandate of the Audit Committee is to assist the Board of Directors in its oversight of the integrity of the financial and related information of the Corporation and its subsidiaries and related entities, including the consolidated financial statements, internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements. In doing so, the Audit Committee oversees the audit efforts of our external auditors and, in that regard, is empowered to take such actions as it may deem necessary to satisfy itself that our external auditors are independent of us. It is the objective of the Audit Committee to have direct, open and frank communications throughout the year with management, other Committee chairs, the external auditors, and other key committee advisors or the Corporation's staff members, as applicable.

The Audit Committee's function is oversight. Management of the Corporation is responsible for the preparation, presentation and integrity of the consolidated financial statements of the Corporation. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies as well as internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Additionally, the Audit Committee reviews the cyber risks facing the Corporation and any related policies for managing cyber risk, as well as the Corporation's enterprise risk management policy, processes and framework and the assessment of enterprise risk management effectiveness by internal audit.

While the Audit Committee has the responsibilities and powers set forth above, it is not the duty of the Audit Committee to plan or conduct audits or to determine whether the consolidated financial statements of the Corporation are complete and accurate and are in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors, on whom the members of the Committee are entitled to rely upon in good faith.

The Audit Committee Mandate is attached hereto as Appendix A.

Relevant Education and Experience of Audit Committee Members

The following is a brief summary of the education or experience of each member of the Audit Committee that is relevant to the performance of his or her responsibilities as a member of the Audit Committee, including any education or experience that has provided the member with an understanding of the accounting principles used by us to prepare our annual and interim consolidated financial statements.

Name of Audit Committee Member	Relevant Education and Experience
Ted Goldthorpe	Mr. Ted Goldthorpe is a financial professional who is currently serving as Managing Partner in charge of Global Credit Business for BC Partners since February 2017. Prior thereto, he was the President of Apollo Investment Corporation, Chief Investment Officer of Apollo Investment Management, and Senior Portfolio Manager, U.S. Opportunistic Credit from April 2012 to August 2016. Previously, Mr. Goldthorpe was employed by Goldman Sachs & Co., where he held a variety of positions since joining the firm in 1999. Mr. Goldthorpe joined the Board of Crescent Point in May 2017 and has been serving as the CEO and Board Chair of Mount Logan Capital Inc, Portman Ridge Finance Corporation and Logan Ridge Financial Corporation and serves as President and CEO and Chair of Board of trustees of the Alternative Credit income Fund and Opportunistic Credit Interval Fund. Mr. Goldthorpe also serves as Lead Director of KITS Eyewear Board, to which he was appointed to in January 2021.
	Mr. Goldthorpe received a B.A. in Commerce from Queen's University and is a frequent guest lecturer at leading universities across North America. Mr. Goldthorpe currently serves on the Global Advisory Board for the Queen's School of Business, is on the Board for Canadian Olympic Foundation, and serves on the Board of Directors for Her Justice and Capitalize for Kids.
Mike Jackson	Mr. Mike Jackson worked in the banking sector from 1984 until his retirement in 2016. From 1997 to 2016, he was Managing Director in Scotiabank's Corporate & Investment Banking group focused on the oil & gas industry, including ten years heading the group. For the period 2006-2016, Mr. Jackson served as Financial Advisor to Boards/companies on M&A transactions aggregating over $28 billion. Mr. Jackson joined the Board of Crescent Point in November 2016.
	Mr. Jackson holds a Bachelor of Science degree and a Master of Business Administration, both from Dalhousie University and the ICD.D designation granted by the Institute of Corporate Directors. Additionally, Mr. Jackson completed the Executive Management Program at Queen's University.
François Langlois	Mr. Langlois is an oil and gas executive who brings over 35 years of domestic and international experience to the Crescent Point Board, most recently from his role as Senior Vice President, Exploration & Production with Suncor Energy Inc., where he was responsible for the financial and operating performance of the group from 2011 until his retirement in 2016. Prior thereto, he was Vice President, Unconventional Gas from 2009 to 2010 and held various roles with Petro-Canada from 1982 to 2009, most recently as Vice President, Western Canada Production & North American Exploration.
	Mr. Langlois holds a Bachelor Geological Engineering from Laval University (Quebec City) and the ICD.D designation granted by the Institute of Corporate Directors.
Mindy Wight	Ms. Mindy Wight brings over 15 years of tax and financial expertise in her current role of Chief Executive Officer for the Nch'kay Development Corporation, as well as holding the role as Treasurer of the Board of Directors. Prior to joining Nch'kay Development Corporation in November 2021, Ms. Wight held progressive tax roles at MNP LLP from 2016 to 2021 and most recently was a partner and National Leader of Indigenous Tax Services for the firm. Ms. Wight has also worked for two of the Big Four National accounting firms, the Chartered Accounting School of Business and the Canada Revenue Agency since graduating from the University of Northern British Columbia with a Bachelor of Commerce Degree, Accounting in 2007. Ms. Wight also possesses Chartered Professional Accountant, Chartered Accountant, and Certified Aboriginal Financial Manager designations.
	Ms. Wight has historically held Board positions as the Chair of the Board of Directors and Chair of the Finance and Audit Committee for the Nch'kay Development Corporation and was an Advisory Committee Member of the Budget and Financial Committee to the Squamish Nation.

External Auditor Services Fees

For services provided to the Corporation and its subsidiaries the years ended December 31, 2022 and 2021 PricewaterhouseCoopers LLP billed approximately $998,961 and $1,297,269, respectively, as detailed below:

	Year ended December 31			
		2022		2021
PricewaterhouseCoopers				
Audit fees	$	952,778	$	1,139,100
Audit-related fees	$	46,183	$	158,169
Tax fees		—		—
All other fees	$	—	$	—
Total	$	998,961	$	1,297,269

The Chair of the Audit Committee has the authority to pre-approve non-audit services which may be required from time to time.

Audit Fees were paid, or are payable, for professional services rendered by the auditors for the audit of the annual financial statements and reviews of the quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements. Audit-related fees consist of the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as Audit fees. The services in this category include participation fees levied by the Canadian Public Accountability Board. All Other Fees were for products or services provided by Crescent Point's auditors other than those described as Audit Fees and Audit-Related Fees. All services described beside the captions "Audit Fees", "Audit-Related Fees", and "All Other Fees" were approved by the Audit Committee in compliance with paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X under the *U.S. Securities and Exchange Act* of 1934, as amended (the "**Exchange Act**"). None of the fees described above were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Regulation S-X under the Exchange Act.

Audit Committee Oversight

At no time since the commencement of our most recently completed financial year, has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the Board of Directors.

TRANSFER AGENT AND REGISTRARS

The transfer agent and registrar for our Common Shares is Computershare Trust Company of Canada in Calgary, Alberta.

AUDITOR

Our auditor is PricewaterhouseCoopers LLP, Chartered Professional Accountants, 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3.

MATERIAL CONTRACTS

Set out below is the only agreement that may be considered material to us:

- Premium Dividend and Dividend Reinvestment Plan.

See "*Additional Information Respecting Crescent Point – Premium Dividend and Dividend Reinvestment Plan*".

INTERESTS OF EXPERTS

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated March 1, 2023 in respect of the Corporation's consolidated financial statements as at December 31, 2022 and December 31, 2021 and the Corporation's internal control over financial reporting as at December 31, 2022. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules of the SEC.

Reserve estimates contained in this AIF are derived from reserve reports prepared by McDaniel. As of the date hereof, McDaniel, as a group, does not beneficially own, directly or indirectly, any Common Shares.

ADDITIONAL INFORMATION

Additional financial information is available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar and on our website at www.crescentpointenergy.com.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in our information circular in respect of the annual meeting of Shareholders held on May 19, 2022, which is available on SEDAR. Additional financial information is provided in our comparative consolidated financial statements for our most recently completed financial year ended December 31, 2022 and MD&A.

For additional copies of this AIF please contact:

Crescent Point Energy Corp.
2000, 585 – 8th Avenue, S.W.
Calgary, Alberta
T2P 1G1

Attention: Investor Relations

APPENDIX A

CRESCENT POINT ENERGY CORP.

AUDIT COMMITTEE MANDATE

CORPORATE POLICIES & PROCEDURES

I. THE BOARD OF DIRECTORS' MANDATE FOR THE AUDIT COMMITTEE

1. General

The Board of Directors (the "Board") has responsibility for the stewardship of Crescent Point Corp. ("Crescent Point") and its subsidiaries or related entities (collectively referred to as herein as the "Corporation"). To discharge that responsibility, the Board is obligated by the *Business Corporations Act* (Alberta) to supervise the management of the business and affairs of the Corporation. The Board's supervisory function involves Board oversight or monitoring of all significant aspects of the management of the Corporation's business and affairs.

Public financial reporting and disclosure by the Corporation are fundamental to the Corporation's business and affairs and to its status as a publicly listed enterprise. The objective of the Board's monitoring of the Corporation's financial reporting and disclosure is to gain reasonable assurance of the following (including, where advisable in the achievement of this objective, through appropriate consultation with senior management and the Corporation's external auditors):

(a) that the Corporation complies with all applicable laws, regulations, rules, policies and other requirement of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;

(b) that the accounting principles, significant judgments and disclosures which underlie or are incorporated in the Corporation's consolidated financial statements are the most appropriate in the prevailing circumstances;

(c) that the Corporation's quarterly and annual consolidated financial statements and management's discussion and analysis, and the Corporation's Annual Information Forms ("AIF") are accurate within a reasonable level of materiality and present fairly the Corporation's financial position and performance in accordance with the recognition and measurement principles of International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"); and

(d) that appropriate information concerning the financial position and performance of the Corporation is disseminated to the public in a timely manner in accordance with corporate and securities law and with stock exchange regulations.

The Board is of the view that monitoring of the Corporation's financial reporting and disclosure policies and procedures cannot be reliably met unless the following activities (the "Fundamental Activities") are conducted effectively:

(i) the Corporation's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Corporation's financial transactions;

(ii) the internal financial controls are regularly assessed for effectiveness and efficiency;

(iii) the Corporation's accounting functions are performed in a manner sufficient to ensure the Corporation has established and continues to maintain disclosure controls and procedures and internal control over financial reporting that meet the requirements of applicable laws, rules and regulations and allows the Chief Executive Officer and the Chief Financial Officer to certify the same;

(iv) the Corporation's quarterly and annual consolidated financial statements are properly prepared by management to comply with IFRS; and

(v) the Corporation's quarterly and annual consolidated financial statements and Management Discussion and Analysis ("MD&A") are reported on by an external auditor appointed by the shareholders of the Corporation.

To assist the Board in its monitoring of the Corporation's financial reporting and disclosure and to conform to applicable corporate and securities law, the Board has established the Audit Committee (the "Committee") of the Board.

2. Role of the Committee

The role of the Committee is to assist the Board in its oversight of: (i) the integrity of the financial and related information of the Corporation, including its consolidated financial statements, the internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements; (ii) the Corporation's supply chain management process and procedures; (iii) the Corporation's enterprise risk management policy and framework; and (iv) the independence, qualifications and performance of the external auditor of the Corporation. Management is responsible for establishing and maintaining those controls, procedures and processes and the Committee is appointed by the Board to review and monitor them.

The Committee has the authority to conduct any review or investigation appropriate to fulfilling its responsibilities. The Committee shall have unrestricted access to personnel and information, and any resources necessary to carry out its responsibility. In this regard, the Committee may direct internal audit personnel to particular areas of examination.

3. Composition of Committee

(a) The Committee shall be appointed annually by the Board and consist of at least three members (the "Members") from among the directors of the Corporation.

(b) Each Member must be an independent, non-executive director, free from any relationship that would interfere with the exercise of the Member's independent judgement. Members shall meet the independence and experience requirements of the regulatory bodies to which the Corporation is subject. Each Member shall have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements at the time of the Member's appointment to the Committee. At least one Member shall have accounting or related financial management expertise and qualify as a "financial expert" or similar designation in accordance with the requirements of the regulatory bodies to which the Corporation is subject.

(c) Committee members may not, other than in their respective capacities as members of the Committee, the Board or any other committee of the Board, accept directly or indirectly any consulting, advisory or other compensatory fee from the Corporation or any subsidiary of the Corporation, or be an "affiliated person" (as such term is defined in the *United States Securities Exchange Act* of 1934, as amended, and the rules, if any, adopted by the U.S. Securities and Exchange Commission thereunder) of the Corporation or any subsidiary of the Corporation. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation that are not contingent on continued service should be the only compensation a Committee member receives from the Corporation.

(d) At least one member shall have experience in the oil and gas industry.

(e) Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.

(f) The Board shall designate the Chair of the Committee.

(g) The Chair of the Board shall be an *ex officio* member of the Committee and shall be entitled to attend all meetings of the Committee.

(h) In the event of either: (i) a vacancy arising in the Committee that reduces the size of the Committee to fewer than three members; or (ii) the loss of independence of any Member, the Committee will fill the vacancy or replace the Member that has lost independence, as applicable, within six weeks or by the following annual shareholders' meeting if sooner.

4. Reliance on Experts

In contributing to the Committee's discharging of its duties under this mandate, each Member of the Committee shall be entitled to rely in good faith upon:

(a) consolidated financial statements of the Corporation represented to the Member by an officer of the Corporation or in a written report of the external auditors to present fairly the financial position of the Corporation in accordance with IFRS; and

(b) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

5. Limitations on The Committee's Duties

In contributing to the Committee's discharging of its duties under this Mandate, each Member shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this Mandate is intended, or may be construed, to impose on any Member a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the objectives of the Corporation's financial reporting are being met and to enable the Committee to report thereon to the Board.

II. AUDIT COMMITTEE MANDATE

This Mandate outlines how the Committee will satisfy the requirements set forth by the Board in its mandate.

1. Operating Principles

The Committee shall fulfill its responsibilities within the context of the following principles.

Committee Values

The Committee expects the management of the Corporation to operate in compliance with corporate policies; reflecting laws and regulations governing the Corporation; and to maintain strong financial reporting and control processes.

Communications

The Committee and its Members expect to have direct, open and frank communications throughout the year with management, other Committee Chairs, the external auditors, and other key Committee advisors or Company staff members as applicable.

Delegation

The Committee may delegate from time to time to any person or committee of persons any of the Committee's responsibilities that may be lawfully delegated.

Annual Audit Committee Plan

The Committee, in consultation with management and the external auditors, shall develop an annual Audit Committee plan responsive to the Committee's responsibilities as set out in this Mandate. In addition, the Committee, in consultation with management and the external auditors, shall develop and participate in a process for review of important financial topics that have the potential to impact the Corporation's financial disclosure.

The plan will be focused primarily on the annual and interim consolidated financial statements and MD&A of the Corporation; however, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the requirements of this Mandate.

Committee Expectations and Information Needs

The Committee shall communicate its expectations to management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at a reasonable time in advance of meeting dates.

Access to Independent Advisors

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditors, at the expense of the Corporation, retain one or more persons, firms or corporations having special expertise.

Reporting to the Board, Shareholders and Others

The Committee, through its Chair, shall report after each Committee meeting to the Board at the Board's next regular meeting. In addition, the Committee shall prepare a report to shareholders or others, concerning the Committee's activities in the discharge of its responsibilities, when and as required by applicable laws, rules, policies or regulations.

Evaluation

The Committee will conduct and present to the Board an annual evaluation of the performance of the Committee and the adequacy of this Mandate and recommend any proposed changes to the Board for approval.

Access to the Committee

Representatives of the Auditor and management of the Corporation shall have access to the Committee each in absence of the other.

The External Auditors

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditors shall be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues, either specific to the Corporation or to the financial reporting environment in general, to the Committee.

No Alteration

No alteration to the roles and responsibilities of the Committee shall be effective without the approval of the Board.

2. Operating Procedures

Meetings

The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair, upon the request of two (2) Members or at the request of the external auditors.

Quorum

A quorum shall be a majority of the Members.

Notice of Meeting

Notice of the time and place of every meeting shall be given in writing by any means of transmitted or recorded communication, including email or other electronic means that produces a written copy, to each Member of the Committee at least 24 hours prior to the time fixed for such meeting; provided however, that a Member may in any manner waive a notice of the meeting. Attendance of a Member at a meeting constitutes waiver of notice of the meeting, except where a Member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

Meeting Agenda

Committee meeting agendas shall be the responsibility of the Chair of the Committee in consultation with other Members, senior management and the external auditors.

Procedure, Records and Reporting

Subject to any statute or the articles and by-laws of the Corporation, the Committee shall fix its own procedures at meetings, keep records of its proceedings and report to the Board when the Committee may deem appropriate (but not later than the next regularly scheduled meeting of the Board).

In Camera Meetings

At the discretion of the Committee, the Members shall meet in private session with the external auditors and with management only.

Referral to the Board

Any matter the Committee does not unanimously approve will be referred to the Board for consideration.

Secretary

Unless the Committee otherwise specifies, the Corporate Secretary (or the Associate General Counsel or other person authorized by the Corporate Secretary and acceptable to the Chair of the Committee) of the Corporation shall act as Secretary of all meetings of the Committee.

Acting Chair

In the absence of the Chair of the Committee, the Members shall appoint an acting Chair.

Minutes

A copy of the minutes of each meeting of the Committee shall be provided to each Member and to each director of the Corporation in a timely fashion.

Attendance at Meetings

The Chief Executive Officer, the Chief Financial Officer, the Senior Vice President, Finance and the internal audit staff are expected to be available to attend the Committee's meetings or portions thereof, and the Chief Executive Officer is entitled to attend all meetings of the Committee.

The Committee may, by specific invitation, have other resource persons in attendance.

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Committee Chair or by a majority of the members of the Committee.

3. Specific Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

Financial Information and Reporting

(a) Review, prior to public release, the Corporation's annual and quarterly consolidated financial statements with management and the external auditors to gain reasonable assurance that the statements are accurate within reasonable levels of materiality, complete, represent fairly the Corporation's financial position and performance and are in accordance with IFRS and report thereon to the Board before such consolidated financial statements are approved by the Board;

(b) Receive from the external auditors reports on their review of the annual and quarterly consolidated financial statements;

(c) Receive from management a copy of the representation letter provided to the external auditors and receive from management any additional representations required by the Committee;

(d) Review, prior to public release, all news releases issued by the Corporation with respect to the Corporation's annual and quarterly consolidated financial statements; and

(e) Review, prior to public release, prospectuses, material change disclosures of a financial nature, management discussion and analysis, AIF and similar disclosure documents to be issued by the Corporation.

Accounting Policies

(a) Review with management and the external auditors the appropriateness of the Corporation's accounting policies, disclosures, reserves, key estimates and judgments, including changes or variations thereto;

(b) Obtain reasonable assurance that the accounting policies, disclosures, reserves, key estimates and judgments are in compliance with IFRS from management and external auditors and report thereon to the Board;

(c) Review with management and the external auditors the degree of conservatism of the Corporation's underlying accounting policies, key estimates and judgments and reserves along with quality of financial reporting; and

(d) Participate, if requested, in the resolution of disagreements between management and the external auditors.

Risk and Uncertainty

(a) Acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Corporation, determine the Corporation's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:

(i) reviewing with management the Corporation's tolerance for financial risks;

(ii) reviewing with management its assessment of the significant financial risks facing the Corporation;

(iii) reviewing with management the Corporation's policies and any proposed changes thereto for managing those significant financial risks; and

(iv) reviewing with management its plans, processes and programs to manage and control such risks.

(b) Review with management its assessment of the cyber risks facing the Corporation and any related policies and any proposed changes thereto for managing cyber risk;

(c) Annually review the enterprise risk management policy, processes and framework and the assessment of enterprise risk management effectiveness by internal audit;

(d) Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

(e) Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

(f) Review the adequacy of insurance coverages maintained by the Corporation; and

(g) Review regularly with management, the external auditors and the Corporation's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these matters have been disclosed in the consolidated financial statements.

Financial Controls and Control Deviations

(a) Review the plans of the external auditors to gain reasonable assurance that the evaluation and testing of internal financial controls is comprehensive, coordinated and cost effective;

(b) Receive regular reports from management and the external auditors on all significant deviations from IFRS or other Company internal control processes or indications which may suggest fraud and the corrective activity undertaken in respect thereto; and

(c) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Board or the Committee concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgment, through existing reporting structures in the Corporation.

Compliance with Laws and Regulations

(a) Receive and review regular reports from management and others (e.g. external auditors) with respect to the Corporation's compliance with laws and regulations having a material impact on the consolidated financial statements including:

(i) tax and financial reporting laws and regulations;

(ii) legal withholding requirements; and

(iii) other laws and regulations which expose directors to liability; and

(b) Review the filing status of the Corporation's tax returns and those of its subsidiaries or related entities.

Relationship and External Auditors

(a) Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Corporation. The external auditors shall report directly to the Committee;

(b) Recommend to the Board the nomination of the external auditors;

(c) Pre approve and recommend to the Board the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter. The Chair of the Committee hereby has the authority to pre approve non audit services which may be required from time to time;

(d) Review the performance of the external auditors annually or more frequently as required;

(e) Receive annually from the external auditors an acknowledgement in writing that the shareholders, as represented by the Board and the Committee, are their primary client;

(f) Receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non audit services by the Corporation;

(g) Review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ;

(h) Meet with the external auditors at least once a year in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee;

(i) Establish effective communication processes with management and the Corporation's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee; and

(j) Establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgment of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee of any disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

Relationship with Internal Auditor

(a) Review the internal audit staff functions, including:

(i) the purpose, authority and organizational reporting lines;

(ii) the annual audit plan, budget and staffing; and

(iii) the appointment and compensation of any person with the responsibility for the Internal Audit; and

(b) Review, with the Chief Financial Officer, controller or others, as appropriate, the Corporation's internal system of audit controls and the results of internal audits.

Other Responsibilities and Procedures

(a) After consultation with the Chief Financial Officer, the Senior Vice President Finance and the external auditors, gain reasonable assurance, at least annually, of the quality and sufficiency of the Corporation's accounting and financial personnel and other resources;

(b) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

(c) Determine the appropriate funding for payment by the Corporation (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, (ii) of compensation to any advisors employed by the Committee, and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties; and

(d) Perform such other functions as may from time to time be assigned to the Committee by the Board.

III. HIRING GUIDELINES FOR INDEPENDENT AUDITOR EMPLOYEES

1. Guidelines

The Committee has adopted the following guidelines regarding the hiring of any partner, employee, reviewing tax professional or other person providing audit assurance to the external auditor of the Corporation on any aspect of its certification of the Corporation's consolidated financial statements:

(a) No senior member of the audit team that is auditing a business of the Corporation can be hired into that business or into a position to which that business reports for a period of two years after the audit; and

(b) No former partner or employee of the external auditor may be made an officer of the Corporation or any of its subsidiaries for two years following association with the external auditor:

(i) The Chief Executive Officer must approve all office hires from the external auditor; and

(ii) The Chief Financial Officer must report annually to the Committee on any hires within these guidelines during the preceding year.

2. Audit Partner Rotation

The Committee will ensure that the head audit partner assigned by the external auditor to the Corporation, as well as the audit partner charged with reviewing the audit of the Corporation, are changed at least every five years.

3. Process for Handling Complaints about Accounting Matters

The Committee will establish the following procedures for the receipt and treatment of any complaint received by the Corporation, including confidential, anonymous submissions by employees of the Corporation and by third parties, regarding accounting, internal accounting controls, auditing or other matters and create a summary of any significant investigations regarding such matters:

(a) The Corporation will publish on its website special mail and e-mail addresses and a toll-free telephone number for receiving complaints regarding accounting, internal accounting controls, auditing matters and other matters;

(b) Copies of all complaints will be sent to the Chair of the Committee and to the Chair of the Board and to the Chair of those other committees of the Board responsible for the oversight of the subject matter of the complaint;

(c) Copies of complaints relating to accounting, internal accounting controls and auditing matters received will be sent to the Members of the Committee;

(d) All complaints will be investigated by the Corporation's finance and legal staffs in the normal manner, except as otherwise directed by the Committee. The Committee may request that outside advisors be retained to investigate any complaint; and

(e) The status of each complaint will be reported on a quarterly basis to the Committee and, if the Committee so directs, to the full board.

APPENDIX B

RESERVES COMMITTEE TERMS OF REFERENCE

CORPORATE POLICIES & PROCEDURES

PURPOSE

The Reserves Committee (the "Committee") is appointed by the Board of Directors of Crescent Point Energy Corp. (the "Board") to assist the Board in fulfilling its responsibility for the stewardship of Crescent Point Energy Corp. ("Crescent Point") and its subsidiaries or related entities (collectively referred to herein as the "Corporation"). The Committee's primary duties and responsibilities are to assume responsibility for assisting the Board in respect of the annual independent review of Crescent Point's petroleum and natural gas reserves and reporting to the Board in respect thereof.

RESERVES COMMITTEE RESPONSIBILITIES AND DUTIES

The overall duties and responsibilities of the Committee shall be as follows:

(a) in conjunction with the Corporation's senior engineering management, meet with the independent evaluating engineers being considered for appointment to review their qualifications and independence to ensure the independent evaluating engineers being considered for appointment are technically qualified and competent, are independent of management and to establish the terms of their engagement;

(b) after consultation with the Corporation's senior engineering management, recommend to the Board the appointment of the independent evaluating engineers to assist the Corporation in the annual review of its petroleum and natural gas reserves;

(c) in consultation with the Corporation's senior engineering management determine the scope of the annual review of the petroleum and natural gas reserves by the independent evaluating engineers, having regard to regulatory reporting requirements;

(d) review, with reasonable frequency, the Corporation's procedures for providing petroleum and natural gas reserves information to the qualified independent evaluating engineers who report on reserves data for the purposes of National Instrument 51 - 101, and the information used by the independent evaluating engineers to enable the independent evaluating engineers to provide a report that will meet regulatory reporting requirements;

(e) in consultation with the Corporation's senior engineering management and the independent evaluating engineers:

- determine whether any restrictions affect the ability of the independent evaluating engineers to report on reserve data without reservations; and

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- review the reserves data and the report of the independent evaluating engineers.

(f) ensure the disclosure to the public on the Corporation's petroleum and natural gas reserves is in compliance with regulatory requirements and make appropriate changes, reports or recommendations to the Board with respect to the procedures for such disclosure;

(g) review any proposal to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;

(h) meet on an annual basis with the Corporation's senior engineering management and/or the independent evaluating engineers of the Corporation to review and consider the evaluation of the Corporation's petroleum and natural gas reserves;

(i) meet separately with the independent evaluating engineers and/or senior engineering management when the Committee deems it desirable and advise the Board on the results of such meeting;

(j) coordinate meetings with the Audit Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation's evaluation of petroleum and natural gas reserves;

(k) review annually the Committee charter and recommend any changes to the Board; and

(l) to maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

COMMITTEE MEMBERS' DUTIES IN ADDITION TO THOSE OF DIRECTOR

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board.

REPORTING

The Committee shall report to the Board. The Committee shall provide the Board with a summary of all meetings held at a regularly scheduled meeting of the Board held following any Committee meetings.

COMPOSITION

The Committee will be comprised of at least three members as determined by the Board. The Committee members shall satisfy the independence and experience requirements of applicable securities laws, rules, or guidelines, any applicable stock exchange requirements or guidelines and any other applicable regulatory rules. In particular, a majority of the members of the Committee shall be free from any relationship which could reasonably be expected to materially interfere with the member's independent judgment. Determinations as to whether a particular director satisfies the requirements for membership on the Committee shall be made by the full Board and shall be reviewed at least annually.

The Chair of the Board shall be an *ex officio* member of the Committee and shall be entitled to attend all meetings of the Committee.

Committee members will include only duly-elected directors. Members of the Committee shall be appointed from time to time by the Board. Each member shall serve until such member's successor is appointed, unless such member resigns or is removed by the Board or such member otherwise ceases to be a director of the Corporation. If a member of the Committee ceases to be independent for reasons outside that member's reasonable control, the member shall immediately notify the Chair of the Board as to this fact and shall resign such member's position on the Committee on the earliest of (i) the appointment of such member's successor; (ii) the next annual meeting of shareholders of the Corporation; and (iii) the date that is six months from the occurrence of the event which caused the member to not be independent. The Board shall fill any vacancy if the membership of the Committee is less than three directors.

CHAIR

The Board shall appoint the Chair of the Committee or, if it does not do so, the members of the Committee may elect a Chair by a vote of a majority of the full Committee membership. The Chair shall be an independent director. If the Chair of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen to preside by a majority of the members of the Committee present at such meeting.

SECRETARY

The Corporate Secretary of the Corporation, the Associate General Counsel or such other person as the Corporate Secretary of the Corporation shall designate from time to time, shall be the Secretary of the Committee and shall keep minutes of the meetings of the Committee.

OPERATION OF COMMITTEE MEETINGS

The Committee shall have access to such officers and employees of the Corporation and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities. The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any such counsel and advisors, such engagement to be for the Corporation's sole account and expense.

Committee meetings may, by agreement of the Chair of the Committee, be held in person, by means of telephone or by a combination of any of the foregoing.

Meetings of the Committee shall be conducted as follows:

(1) The Committee shall meet at least two times annually at such times and at such locations as the Chair of the Committee shall determine. Any two members of the Committee may also request a meeting of the Committee.

(2) The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other.

(3) The Chair shall, in consultation with management, establish the agenda for the meetings and instruct management to ensure that properly prepared agenda materials are circulated to the Committee with sufficient time for study prior to the meeting.

(4) Every question at a Committee meeting shall be decided by a majority of the votes cast.

(5) The Chief Executive Officer is expected to be available to attend the Committee's meetings or portions thereof. The Committee may, by specific invitation, have other resource persons in attendance. The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee, provided that the Chief Executive Officer of the Corporation is entitled to attend all meetings of the Committee. Directors, who are not members of the Committee, may attend Committee meetings on an ad hoc basis upon prior consultation and approval by the Committee Chair or by a majority of the members of the Committee.

(6) The Committee may delegate from time to time to any person or committee of persons any of the Committee's responsibilities that lawfully may be delegated.

(7) Minutes of each Committee meeting should be succinct yet comprehensive in describing substantive issues discussed by the Committee. However, they should clearly identify those items of responsibilities scheduled by the Committee for the meeting that have been discharged by the Committee and those items of responsibilities that are outstanding. Minutes of the Committee meeting shall be sent firstly to the Chair and next to all Committee members.

NOTICE OF MEETING

Notice of the time and place of each meeting may be given in writing, by electronic means, or orally to each member of the Committee at least 24 hours prior to the time fixed for such meeting.

A member may in any manner waive notice of the meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

MISCELLANEOUS

The Committee, with unanimity, may engage outside resources if deemed advisable. Lack of unanimity requires that the matter be referred to the Nominating and Corporate Governance Committee.

Appendix C

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Crescent Point Energy Corp. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2022, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel	December 31, 2022	Canada	—	10,740,688	—	10,740,688
McDaniel	December 31, 2022	United States	—	1,719,075	—	1,719,075
		Total	**—**	**12,459,763**	**—**	**12,459,763**

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

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.

8. Because the reserves data are based on judgements 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.

ORIGINALLY SIGNED BY

Michael J. Verney, P.Eng.
Executive Vice President

Calgary, Alberta, Canada
February 7, 2023

Appendix D

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Crescent Point Energy Corp. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator, has evaluated the Corporation's reserves data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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

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

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

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

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

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

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

(c) the content and filing of this report.

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

"Craig Bryksa"	*"Ryan Gritzfeldt"*
CRAIG BRYKSA President and Chief Executive Officer	RYAN GRITZFELDT Chief Operating Officer
"Francois Langlois"	*"Barbara Munroe"*
FRANCOIS LANGLOIS Director	BARBARA MUNROE Chair of the Board

March 1, 2023

Exhibit 99.2

MANAGEMENT'S REPORT

MANAGEMENT’S RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Crescent Point Energy Corp. is responsible for the preparation of the consolidated financial statements. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect management’s best estimates and judgments. Management has determined such amounts on a reasonable basis in order to determine that the consolidated financial statements are presented fairly in all material respects.

PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants, was appointed by a resolution of the Board of Directors to audit the consolidated financial statements of the Company and to provide an independent professional opinion. PricewaterhouseCoopers LLP was appointed to hold such office until the next annual meeting of the shareholders of the Company.

The Board of Directors, through its Audit Committee, has reviewed the consolidated financial statements including notes thereto with management and PricewaterhouseCoopers LLP. The members of the Audit Committee are composed of independent directors who are not employees of the Company. The Audit Committee meets regularly with management and PricewaterhouseCoopers LLP to review and approve the consolidated financial statements. The Board of Directors has approved the information contained in the consolidated financial statements based on the recommendation of the Audit Committee.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management has developed and maintains an extensive system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the consolidated financial statements realistically report the Company’s operating and financial results, and that the Company’s assets are safeguarded. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Management has assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2022. The assessment was based on the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control - Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Management concluded that this system of internal controls was effective as of December 31, 2022. The Company has effective disclosure controls and procedures to ensure timely and accurate disclosure of material information relating to the Company which complies with the requirements of Canadian securities legislation and the United States Sarbanes - Oxley Act of 2002.

PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants who also audited the Company's consolidated financial statement for the year ended December 31, 2022, has audited the effectiveness of the Company's internal control over financial reporting as at December 31, 2022.

Craig Bryksa
President and Chief Executive Officer

Ken Lamont
Chief Financial Officer

March 1, 2023

pwc

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Crescent Point Energy Corp.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Crescent Point Energy Corp. and its subsidiaries (together, the Company) as of December 31, 2022 and 2021, and the related consolidated statements of comprehensive income, changes in shareholders' equity and cash flows for the years then ended, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and its financial performance and its cash flows for the years then ended in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters
The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.
The Impact of Estimates of Proved Plus Probable Oil and Gas Reserves on Development and Production Assets, Net

As described in Notes 2, 3 and 8 to the consolidated financial statements, the Company had a net balance of $7,688.2 million for development and production assets as of December 31, 2022. Management also recorded a depletion expense of $911.4 million and an impairment reversal of $428.6 million for the year ended December 31, 2022. Development and production assets are measured at cost less accumulated depletion and any accumulated impairment losses. As disclosed by management, proved plus probable oil and gas reserves are used as the basis to calculate the unit-of-production depletion expense. Management assesses the recoverability of development and production assets by grouping these assets into cash-generating units (CGUs) based on the integration between assets, shared infrastructure, the existence of common sales points, geography, geological structure and the manner in which management monitors the decisions regarding operations. The recoverable amounts of CGUs are estimated when impairment indicators exist. If the carrying amount of the CGU, which takes into account the discounted abandonment and reclamation costs on proved plus probable undeveloped oil and gas reserves, exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined, net of depletion, had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net income. The recoverable amount is the higher of fair value less costs of disposal and the value-in-use. Management determines the recoverable amount using a fair value less costs of disposal derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves.

Determining the Company’s proved plus probable oil and gas reserves and the fair value less costs of disposal required the use of significant estimates and judgment by management related to production forecasts, commodity prices, costs and related future cash flows as well as the discount rate, as applicable. In determining the estimates of the proved plus probable oil and gas reserves, management utilizes the services of specialists, specifically independent petroleum reservoir engineers.

The principal considerations for our determination that performing procedures relating to the impact of estimates of proved plus probable oil and gas reserves on development and production assets, net is a critical audit matter are that there was significant judgment used by management, including the use of management's specialists, when developing the estimates of proved plus probable oil and gas reserves, and determining the recoverable amount for each CGU. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate the significant assumptions used by management in developing those estimates, including production forecasts, commodity prices, costs and related future cash flows and the discount rate, as applicable. Our audit effort also involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved plus probable oil and gas reserves, management's determination of the recoverable amounts of each CGU and the calculation of depletion expense. These procedures also included, among others, testing management's processes for determining the recoverable amount for each CGU and depletion expense for development and production assets, which included evaluating the appropriateness of the methods used by management in making these estimates; testing the completeness and accuracy of underlying data used in management's analysis in developing these estimates; and evaluating the significant assumptions used by management, including production forecasts, commodity prices, costs and related future cash flows. Procedures were also performed to test the unit-of-production rates used to calculate depletion expense. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of the recoverable amount, including the discount rate used within the discounted cash flow model for each CGU. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved plus probable oil and gas reserves. As a basis for using this work, management's specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by management's specialists and an evaluation of the specialists' findings. Evaluating the assumptions used by management's specialists also involved assessing whether the assumptions used were reasonable considering the current and past performance of the Company, whether they were consistent with industry pricing forecasts and evidence obtained in other areas of the audit.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
March 1, 2023

We have served as the Company's auditor since 2001.

CONSOLIDATED BALANCE SHEETS

As at December 31			
(Cdn$ millions)	Notes	**2022**	2021
ASSETS			
Cash		**289.9**	13.5
Accounts receivable		**327.8**	314.3
Deposit on acquisition	31	**18.7**	—
Prepaids and deposits		**65.5**	7.4
Derivative asset	25	**138.9**	75.7
Assets held for sale	7	**148.4**	—
Total current assets		**989.2**	410.9
Derivative asset	25	**96.4**	144.8
Other long-term assets	5	**6.4**	6.4
Exploration and evaluation	6, 7	**104.2**	48.8
Property, plant and equipment	7, 8	**7,729.4**	7,687.3
Right-of-use asset	12	**78.1**	91.4
Goodwill	9	**203.9**	211.5
Deferred income tax	22	**278.8**	570.1
Total assets		**9,486.4**	9,171.2
LIABILITIES			
Accounts payable and accrued liabilities		**448.2**	450.7
Dividends payable		**99.4**	43.5
Current portion of long-term debt	11	**538.7**	278.1
Derivative liability	25	**8.7**	159.6
Other current liabilities	10	**115.6**	100.3
Liabilities associated with assets held for sale	7	**28.4**	—
Total current liabilities		**1,239.0**	1,032.2
Long-term debt	11	**902.8**	1,692.1
Derivative liability	25	**—**	5.3
Other long-term liabilities	13	**40.8**	35.8
Lease liability	12	**99.2**	115.9
Decommissioning liability	7, 14	**633.9**	884.6
Deferred income tax	22	**77.3**	—
Total liabilities		**2,993.0**	3,765.9
SHAREHOLDERS’ EQUITY			
Shareholders’ capital	15	**16,419.3**	16,706.9
Contributed surplus		**17.1**	17.5
Deficit	16	**(10,563.3)**	(11,848.7)
Accumulated other comprehensive income		**620.3**	529.6
Total shareholders' equity		**6,493.4**	5,405.3
Total liabilities and shareholders' equity		**9,486.4**	9,171.2

Commitments (Note 27)

Subsequent Events (Note 31)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

Barbara Munroe	Mike Jackson
Chair of the Board	Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31			
(Cdn$ millions, except per share amounts)	Notes	**2022**	2021
REVENUE AND OTHER INCOME			
Oil and gas sales	30	**4,493.1**	3,206.5
Purchased product sales		**100.8**	31.7
Royalties		**(600.9)**	(408.8)
Oil and gas revenue		**3,993.0**	2,829.4
Commodity derivative losses	18, 25	**(473.4)**	(488.9)
Other income	19	**58.8**	99.4
		3,578.4	2,439.9
EXPENSES			
Operating		**713.1**	625.3
Purchased product		**102.9**	32.6
Transportation		**139.8**	117.7
General and administrative		**81.8**	89.8
Interest	20	**63.6**	90.6
Foreign exchange (gain) loss	21	**18.8**	(4.4)
Share-based compensation	23	**39.1**	30.9
Depletion, depreciation and amortization	6, 8, 12	**951.7**	786.1
Impairment reversal	8	**(428.6)**	(2,514.4)
Accretion and financing	12, 14	**24.9**	21.9
		1,707.1	(723.9)
Net income before tax		**1,871.3**	3,163.8
Tax expense			
Current	22	**—**	—
Deferred	22	**387.9**	799.7
Net income		**1,483.4**	2,364.1
Other comprehensive income			
Items that may be subsequently reclassified to profit or loss			
Foreign currency translation of foreign operations		**90.7**	11.9
Comprehensive income		**1,574.1**	2,376.0
Net income per share	24		
Basic		**2.62**	4.15
Diluted		**2.60**	4.11

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Cdn$ millions, except per share amounts)	Notes	Shareholders' capital	Contributed surplus	Deficit	Accumulated other comprehensive income	Total shareholders' equity
December 31, 2020		16,451.5	19.7	(14,166.1)	517.7	2,822.8
Issued on capital acquisitions		264.5				264.5
Redemption of restricted shares		8.5	(8.8)	1.1		0.8
Common shares repurchased for cancellation		(17.5)				(17.5)
Share issue costs, net of tax		(0.4)				(0.4)
Share-based compensation			6.8			6.8
Stock options exercised		0.3	(0.2)			0.1
Net income				2,364.1		2,364.1
Dividends declared ($0.0825 per share)				(47.8)		(47.8)
Foreign currency translation adjustment					11.9	11.9
December 31, 2021		16,706.9	17.5	(11,848.7)	529.6	5,405.3
Redemption of restricted shares	15	**5.2**	**(5.2)**	**2.6**		**2.6**
Common shares repurchased for cancellation	15	**(294.2)**				**(294.2)**
Share-based compensation	23		**6.2**			**6.2**
Stock options exercised	23	**1.4**	**(1.4)**			**—**
Net income				**1,483.4**		**1,483.4**
Dividends declared ($0.3600 per share)				**(200.6)**		**(200.6)**
Foreign currency translation adjustment					**90.7**	**90.7**
December 31, 2022		**16,419.3**	**17.1**	**(10,563.3)**	**620.3**	**6,493.4**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31			
(Cdn$ millions)	Notes	**2022**	2021
CASH PROVIDED BY (USED IN):			
OPERATING ACTIVITIES			
Net income		**1,483.4**	2,364.1
Items not affecting cash			
Other income	19	**(49.0)**	(97.0)
Deferred tax expense	22	**387.9**	799.7
Share-based compensation		**6.0**	6.1
Depletion, depreciation and amortization	6, 8, 12	**951.7**	786.1
Impairment reversal	8	**(428.6)**	(2,514.4)
Accretion	14	**19.2**	15.4
Unrealized (gains) losses on derivatives	25	**(171.0)**	141.4
Translation of US dollar long-term debt	21	**91.5**	(37.0)
Realized gain on cross currency swap maturity	21	**(63.8)**	—
Decommissioning expenditures	14	**(20.1)**	(20.2)
Change in non-cash working capital	29	**(15.0)**	51.6
		2,192.2	1,495.8
INVESTING ACTIVITIES			
Development capital and other expenditures	6, 8	**(1,027.4)**	(676.1)
Capital acquisitions	7	**(90.7)**	(677.9)
Capital dispositions	7	**283.6**	99.0
Deposit on acquisition	31	**(18.7)**	—
Sale of long-term investments		**—**	12.6
Change in non-cash working capital	29	**(7.4)**	49.0
		(860.6)	(1,193.4)
FINANCING ACTIVITIES			
Share issue costs		**—**	(0.7)
Common shares repurchased for cancellation	15	**(294.2)**	(17.5)
Decrease in bank debt, net	29	**(338.5)**	(34.6)
Repayment of senior guaranteed notes	29	**(281.8)**	(217.6)
Realized gain on cross currency swap maturity	21	**63.8**	—
Payments on principal portion of lease liability	12, 29	**(20.4)**	(21.2)
Dividends declared	29	**(200.6)**	(47.8)
Change in non-cash working capital	29	**15.7**	42.2
		(1,056.0)	(297.2)
Impact of foreign currency on cash balances		**0.8**	(0.5)
INCREASE IN CASH		**276.4**	4.7
CASH AT BEGINNING OF YEAR		**13.5**	8.8
CASH AT END OF YEAR		**289.9**	13.5

See accompanying notes to the consolidated financial statements.

Supplementary Information:

Cash taxes paid	**—**	—
Cash interest paid	**(68.0)**	(93.1)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2022 and 2021

1. STRUCTURE OF THE BUSINESS

The principal undertaking of Crescent Point Energy Corp. (the “Company” or “Crescent Point”) is to carry on the business of acquiring, developing and holding interests in petroleum and natural gas properties and assets related thereto through a general partnership and wholly owned subsidiaries.

Crescent Point is the ultimate parent and is amalgamated in Alberta, Canada under the Alberta Business Corporations Act. The address of the principal place of business is 2000, 585 - 8th Ave S.W., Calgary, Alberta, Canada, T2P 1G1.

These annual consolidated financial statements were approved and authorized for issue by the Company's Board of Directors on March 1, 2023.

2. BASIS OF PREPARATION

a) Preparation

These consolidated financial statements are presented under International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board (“IASB”). The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of March 1, 2023, the date the Board of Directors approved the statements.

The Company’s presentation currency is Canadian dollars and all amounts reported are Canadian dollars unless noted otherwise. References to “US$” and "US dollars" are to United States ("U.S.") dollars. Crescent Point's Canadian and U.S. operations are aggregated into one reportable segment based on similar economic characteristics and the similar nature of the assets, products, production processes and customers.

b) Basis of measurement, functional and presentation currency

The Company’s presentation currency is Canadian dollars. The accounts of the Company’s foreign operations that have a functional currency different from the Company’s presentation currency are translated into the Company’s presentation currency at period end exchange rates for assets and liabilities and at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income as cumulative translation adjustments.

c) Use of estimates and judgments

The preparation of consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected.

The Company also faces uncertainties related to future environmental laws and climate-related regulations, which could affect the Company's financial position and future earnings. This transition to a lower-carbon society, as well as the physical impacts of climate change, could result in increased operating costs and reduced demand for oil and gas products. As a result, this could change a number of variables and assumptions used to determine the estimated recoverable amounts of the Company's oil and gas assets. The unpredictable nature, timing and extent of climate-related initiatives presents various risks and uncertainties, including to management's judgements, estimates and assumptions that affect the application of accounting policies. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below.

Oil and gas activities

Reserves estimates, although not reported as part of the Company’s consolidated financial statements, can have a significant effect on net income, assets and liabilities as a result of their impact on depletion, depreciation and amortization (“DD&A”), decommissioning liability, deferred taxes, asset impairments and impairment reversals, and business combinations. Independent petroleum reservoir engineers perform evaluations of the Company's oil and gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

For purposes of impairment testing, property, plant and equipment ("PP&E") is aggregated into cash-generating units ("CGUs"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructure, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations.

The determination of technical feasibility and commercial viability, based on the presence of reserves and which results in the transfer of assets from exploration and evaluation ("E&E") to PP&E, is subject to judgment.

Decommissioning liability

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are impacted by estimates with respect to the cost and timing of decommissioning.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Fair value measurement

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of derivative instruments include forward benchmark prices, discount rates, share price, forward foreign exchange rates and forward interest rates.

Joint control

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the capital and operating activities of the projects it undertakes with partners and when the decisions in relation to those activities require unanimous consent.

Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax assets and liabilities recognize the extent that temporary differences will be receivable and payable in future periods. The calculation of the asset and liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, expected cash flows from estimated proved plus probable reserves and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently by the Company and its subsidiaries for all periods presented in these annual consolidated financial statements.

a) Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries and any reference to the “Company” throughout these consolidated financial statements refers to the Company and its subsidiaries. All transactions between the Company and its subsidiaries have been eliminated.

The Company conducts some of its oil and gas production activities through jointly controlled operations and the financial statements reflect only the Company's proportionate interest in such activities. Joint control exists for contractual arrangements governing the Company's assets whereby the Company has less than 100 percent working interest, all the partners have control of the arrangement collectively, and share the associated risks. The Company does not have any joint arrangements that are material to the Company or that are structured through joint venture arrangements.

b) Property, Plant and Equipment

Items of PP&E, which primarily consist of oil and gas development and production assets, are measured at cost less accumulated depletion, depreciation and any accumulated impairment losses or impairment reversals. Development and production assets are accumulated into CGUs and account for the cost of developing the commercial reserves and initiating production.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as development and production assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in net income as incurred. Capitalized development and production assets generally represent costs incurred in developing reserves and initiating or enhancing production from such reserves. The carrying amount of any sold component is derecognized.

Depletion and Depreciation

Development and production assets are depleted using the unit-of-production method based on estimated proved plus probable reserves before royalties, as determined by independent petroleum reservoir engineers. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proved plus probable reserves.

Corporate assets are depreciated on a straight line basis over the estimated useful lives of the related assets, ranging from 5 to 16 years.

Impairment

The carrying amounts of PP&E, which takes into account the discounted abandonment and reclamation costs on proved plus probable undeveloped oil and gas reserves, are grouped into CGUs and reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income.

Assets are grouped into CGUs based on the integration between assets, shared infrastructure, the existence of common sales points, geography, geological structure and the manner in which management monitors and makes decisions regarding operations. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent petroleum reservoir engineers. The recoverable amount is the higher of fair value less costs of disposal and the value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate. The fair value less costs of disposal and value in use estimates are categorized as Level 3 according to the IFRS 13 fair value hierarchy.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined, net of depletion, had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net income.

c) Exploration and Evaluation

Exploration and evaluation assets are comprised of the accumulated expenditures incurred in an area where technical feasibility and commercial viability has not yet been determined. Exploration and evaluation assets include undeveloped land and any drilling costs thereon.

Technical feasibility and commercial viability are considered to be determinable when reserves are discovered. Upon determination of reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E.

Costs incurred prior to acquiring the legal rights to explore an area are expensed as incurred.

Amortization

Undeveloped land classified as E&E assets is amortized by major area over the average primary lease term and recognized in net income. Drilling costs classified as E&E assets are not amortized, but are subject to impairment.

Impairment

Exploration and evaluation assets are reviewed quarterly for indicators of impairment and upon reclassification from E&E assets to PP&E. Exploration and evaluation assets are tested for impairment at the operating segment level by combining E&E assets with PP&E. The recoverable amount is the greater of fair value less costs of disposal or value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves, plus the fair market value of undeveloped land. Value-in-use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate.

Impairments of E&E assets are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been, net of amortization, had no impairment been recognized.

d) Decommissioning Liability

The Company recognizes the present value of a decommissioning liability in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis using the relevant risk free rate, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the underlying proved plus probable reserves. Accretion expense is recognized in net income. Revisions to the discount rate, estimated timing or amount of future cash flows would also result in an increase or decrease to the decommissioning liability and related asset.

e) Goodwill

The Company records goodwill relating to business combinations when the purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The goodwill balance is assessed for impairment annually or as events occur that could result in impairment. Goodwill is tested for impairment at an operating segment level by combining the carrying amounts of PP&E, E&E assets and goodwill and comparing this to the recoverable amount. Any excess of the carrying amount over the recoverable amount is the impairment amount. The recoverable amount estimates is categorized as Level 3 according to the IFRS 13 fair value hierarchy. Impairment charges, which are not tax affected, are recognized in net income. Goodwill is reported at cost less any accumulated impairment. Goodwill impairments are not reversed.

f) Share-based Compensation

Restricted shares granted under the Restricted Share Bonus Plan are accounted for at fair value and vest on terms up to three years from the grant date determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and recognized when they occur. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the portion of share-based compensation directly attributable to development activities, with a corresponding decrease to share-based compensation expense. At the time the restricted shares vest, the issuance of shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

Employee Share Value Plan ("ESVP") awards are accounted for at fair value and vest on terms of up to three years from the grant date as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the ESVP awards on the date of grant and subsequently adjusted to reflect the fair value at each period end. The expense is recognized over the service period, with a corresponding increase to long-term compensation liability. ESVP awards are settled in cash upon vesting based on the prevailing Crescent Point share price and the aggregate amount of dividends paid from the grant date.

Performance share units ("PSUs") are accounted for at fair value and vest on terms of up to three years from the grant date as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the PSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Market performance conditions are factored into the fair value and the best estimate of non-market performance conditions is used to determine an estimate of the number of units that will vest. Fair value is based on the expected cash payment per PSU and the expected number of PSUs to vest, calculated from multipliers based on internal and external performance metrics. The expense is recognized over the service period, with a corresponding increase to long-term compensation liability. PSUs are settled in cash upon vesting based on the prevailing Crescent Point share price, the aggregate amount of dividends paid from the grant date and the performance multipliers.

Deferred share units ("DSUs") are accounted for at fair value. Share-based compensation expense is determined based on the estimated fair value of the DSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Fair value is based on the prevailing Crescent Point share price.

Stock options are accounted for at fair value and have a maximum term of seven years and vest on terms as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the stock options on the date of the grant. Upon vesting, the stock option holder may either exercise their stock options to purchase one common share per option at the exercise price or, at the Company's discretion, surrender their stock options for a cash payment in an amount equal to the aggregate positive difference, if any, between the market price and the exercise price of the number of common shares associated with the stock options surrendered. Alternatively, the stock option holder may also, at the Company's discretion, surrender their stock options for common shares having a value equivalent to the cash payment.

g) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the estimated effect of any differences between the accounting and tax basis of assets and liabilities, using enacted or substantively enacted income tax rates expected to apply when the deferred tax asset or liability is settled. The effect of a change in income tax rates on deferred income taxes is recognized in net income in the period in which the change occurs.

The tax expense for the period comprises current and deferred tax. Tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity. In this case, the tax is also recognized in other comprehensive income or directly in equity, respectively.

The Company is able to deduct certain settlements under its Restricted Share Bonus Plan. To the extent the tax deduction exceeds the cumulative remuneration cost for a particular restricted share grant recorded in net income, the tax benefit related to the excess is recorded directly within equity.

A deferred tax asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized. Deferred income tax assets and liabilities are presented as non-current.

h) Financial Instruments

The Company uses financial derivative instruments and physical delivery commodity contracts from time to time to reduce its exposure to fluctuations in commodity prices, share price, foreign exchange rates and interest rates. The Company also makes investments in companies from time to time in connection with the Company's acquisition and divestiture activities.

Financial derivative instruments

Financial derivative instruments are included in current assets/liabilities except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets/liabilities.

The Company has not designated any of its financial derivative contracts as effective accounting hedges and, accordingly, fair values its financial derivative contracts with the resulting gains and losses recorded in net income.

The fair value of a financial derivative instrument on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair values are based on quoted market prices where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at the reporting date.

Financial assets and liabilities

Financial assets and liabilities are measured at fair value on initial recognition. For non-equity instruments, measurement in subsequent periods depends on the classification of the financial asset or liability as "fair value through profit or loss" or "amortized cost".

Financial assets and liabilities classified as fair value through profit or loss are subsequently carried at fair value, with changes recognized in net income.

Financial assets and liabilities classified as amortized cost are subsequently carried at amortized cost using the effective interest rate method.

Currently, the Company classifies all non-equity financial instruments which are not financial derivative instruments as amortized cost.

At each reporting date, the Company assesses whether there is objective evidence that a financial asset carried at amortized cost is impaired. If such evidence exists, the Company recognizes an impairment loss in net income. Impairment losses are reversed in subsequent periods if the impairment loss decrease can be related objectively to an event occurring after the impairment was recognized.

For investments in equity instruments, the subsequent measurement is dependent on the Company's election to classify such instruments as fair value through profit or loss or fair value through other comprehensive income. Currently, the Company classifies all investments in equity instruments as fair value through profit or loss, whereby the Company recognizes movements in the fair value of the investment (adjusted for dividends) in net income. If the fair value through other comprehensive income classification is selected, the Company would recognize any dividends from the investment in net income and would recognize fair value re-measurements of the investment in other comprehensive income.

Impairment of financial assets

Impairment losses are recognized using an expected credit loss model. The Company has adopted the simplified expected credit loss model for its accounts receivable, which permits the use of the lifetime expected loss provision.

To measure the expected credit losses, accounts receivable have been grouped based on shared credit risk characteristics and days past due. The Company uses judgment in making these assumptions and selecting the inputs into the expected loss calculation based on past history, existing market conditions and forward looking estimates at the end of each reporting period.

i) Business Combinations

Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The consideration paid of an acquisition is measured as the fair value of the acquired assets by estimating the discounted after-tax future net cash flows, the fair value of equity instruments issued and the fair value of liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in net income. Transaction costs associated with business combinations are expensed as incurred.

j) Foreign Currency Translation

Foreign operations

The Company has operations in the U.S. transacted via U.S. subsidiaries. The assets and liabilities of foreign operations are translated to Canadian dollars at exchange rates in effect at the balance sheet date. The income and expenses of foreign operations are translated to Canadian dollars using average exchange rates for the period. The resulting unrealized gain or loss is included in other comprehensive income.

Foreign transactions

Transactions in foreign currencies not incurred by the Company’s U.S. subsidiaries are translated to Canadian dollars at exchange rates in effect at the transaction dates. Foreign currency assets and liabilities are translated to Canadian dollars at exchange rates in effect at the balance sheet date and income and expenses are translated to Canadian dollars using average exchange rates for the period. Both realized and unrealized gains and losses resulting from the settlement or restatement of foreign currency transactions are included in net income.

k) Revenue Recognition

The Company’s major revenue sources are comprised of sales from the production of crude oil and condensate, natural gas liquids ("NGLs") and natural gas. Revenue is recognized when control of the product transfers to the customer and the collection is reasonably probable, generally upon delivery of the product. Sales of crude oil and condensate, NGLs and natural gas production are based on variable pricing as the transaction prices are based on benchmark commodity prices and other variable factors, including quality differentials and location.

Each contract is evaluated based on the nature of the performance obligations, including the Company’s role as either principal or agent. Where the Company acts as principal, revenue is recognized on a gross basis. Where the Company acts as agent, revenue is recognized on a net basis.

l) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with original maturities of three months or less.

m) Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the commencement date, the lease liability is recognized at the present value of the future lease payments and discounted using the interest rate implicit in the lease or the Company's incremental borrowing rate. A corresponding right-of-use ("ROU") asset will be recognized at the amount of the lease liability, adjusted for any lease incentives received and initial direct costs incurred. Over the term of the lease, financing expense is recognized on the lease liability using the effective interest rate method and charged to net income, lease payments are applied against the lease liability and depreciation on the ROU asset is recorded by class of underlying asset.

The lease term is the non-cancellable period of a lease and includes periods covered by an optional lease extension option if reasonably certain the Company will exercise the option to extend. Conversely, periods covered by an option to terminate are included if the Company does not expect to end the lease during that time frame. Leases with a term of less than twelve months or leases for underlying low value assets are recognized as an expense in net income on a straight-line basis over the lease term.

A lease modification will be accounted for as a separate lease if it materially changes the scope of the lease. For a modification that is not a separate lease, on the effective date of the lease modification, the Company will remeasure the lease liability and corresponding ROU asset using the interest rate implicit in the lease or the Company's incremental borrowing rate. Any variance between the remeasured ROU asset and lease liability will be recognized as a gain or loss in net income to reflect the change in scope.

The Company also acts as an intermediate lessor for office space sub-leased to other companies. As a lessor, the Company will evaluate whether a lease is a finance or operating lease. Leases where the Company transfers substantially all the risks and rewards of ownership are classified as finance leases. Conversely, leases where the risks and rewards of ownership are retained by the Company are operating leases. The head lease between the Company and the building, and the sub-lease between the Company and tenants, are accounted for separately. The lease classification of the sub-lease is based upon the head lease and not the underlying asset.

n) Earnings Per Share

Basic earnings per share (“EPS”) is calculated by dividing the net income for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period.

Diluted EPS is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to dilutive instruments, being restricted shares issued under the Company’s Restricted Share Bonus Plan and stock options under the Company's Stock Option Plan, is computed using the treasury stock method. The treasury stock method assumes that the deemed proceeds related to unrecognized share-based compensation are used to repurchase shares at the average market price during the period.

o) Government Grants

The Company may receive government grants which provide immediate financial assistance as compensation for costs or expenditures to be incurred. Government grants are accounted for when there is reasonable assurance that conditions attached to the grants are met and that the grants will be received. The Company recognizes government grants in net income on a systematic basis and in line with recognition of the expense that the grants are intended to compensate.

p) Assets Held for Sale

PP&E and E&E assets are classified as held for sale if it is highly probable their carrying amounts will be recovered through a capital disposition rather than through future operating cash flows. Before PP&E and E&E assets are classified as held for sale, they are assessed for indicators of impairment or reversal of previously recorded impairments and are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment charges or reversals are recognized in net income. Assets held for sale are classified as current assets and are not subject to DD&A. Decommissioning liabilities associated with assets held for sale are classified as current liabilities.

4. CHANGES IN ACCOUNTING POLICIES

New accounting standards and amendments not yet adopted

Income Taxes

IAS 12 *Income Taxes* was amended in May 2021 by the IASB which requires companies, on initial recognition, to recognize deferred tax on transactions that result in equal amounts of taxable and deductible temporary differences. The amendment is effective for fiscal years beginning on or after January 1, 2023.

Presentation of Financial Statements

IAS 1 *Presentation of Financial Statements* was amended in January 2020 by the IASB to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. This amendment is effective for fiscal years beginning on or after January 1, 2024.

5. OTHER LONG-TERM ASSETS

At December 31, 2022, other long-term assets relate to investment tax credits of $6.4 million (December 31, 2021 - $6.4 million).

6. EXPLORATION AND EVALUATION ASSETS

($ millions)	2022	2021
Exploration and evaluation assets at cost	**1,453.4**	1,613.3
Accumulated amortization	**(1,349.2)**	(1,564.5)
Net carrying amount	**104.2**	48.8
Reconciliation of movements during the year		
Cost, beginning of year	**1,613.3**	1,736.1
Accumulated amortization, beginning of year	**(1,564.5)**	(1,649.7)
Net carrying amount, beginning of year	**48.8**	86.4
Net carrying amount, beginning of year	**48.8**	86.4
Acquisitions through business combinations	**28.0**	18.6
Additions	**134.2**	57.8
Dispositions	**(10.9)**	(5.4)
Transfers to property, plant and equipment	**(80.8)**	(57.5)
Amortization	**(15.2)**	(51.0)
Foreign exchange	**0.1**	(0.1)
Net carrying amount, end of year	**104.2**	48.8

Impairment test of exploration and evaluation assets

There were no indicators of impairment at December 31, 2022 or December 31, 2021.

7. CAPITAL ACQUISITIONS AND DISPOSITIONS

In the year ended December 31, 2022, the Company incurred $5.1 million (year ended December 31, 2021 - $12.5 million) of transaction costs related to acquisitions through business combinations and dispositions that were recorded as general and administrative expenses.

a) Major property acquisitions and dispositions

Saskatchewan Viking disposition

On July 6, 2022, the Company disposed of its non-core Saskatchewan Viking assets for consideration of $241.7 million. These assets had a net carrying value of $219.1 million, resulting in a gain of $22.6 million.

Kaybob Duvernay acquisition

On August 31, 2022, the Company acquired certain Kaybob Duvernay assets for total consideration of $87.0 million.

b) Minor property acquisitions and dispositions

In the year ended December 31, 2022, the Company completed minor property acquisitions and dispositions for net consideration received of $38.2 million. These assets had a net carrying value of $34.9 million, resulting in a gain of $3.3 million.

The following table summarizes the major and minor property acquisitions and dispositions:

($ millions)	Saskatchewan Viking Disposition	Kaybob Duvernay Acquisition	Other minor dispositions, net
Cash	241.7	(87.0)	38.2
Consideration (paid) received	**241.7**	**(87.0)**	**38.2**
Exploration and evaluation	—	28.0	(10.9)
Property, plant and equipment	(252.5)	61.8	(29.1)
Goodwill	(6.8)	—	(0.8)
Decommissioning liability	40.2	(2.8)	5.9
Fair value of net assets acquired (Carrying value of net assets disposed)	**(219.1)**	**87.0**	**(34.9)**
Gain on capital dispositions	**22.6**	**—**	**3.3**

c) Assets held for sale

At December 31, 2022, the Company classified certain non-core assets in Alberta as held for sale. These assets were recorded at the lesser of their carrying value and recoverable amount.

($ millions)	**PP&E** (Note 8)	**Decommissioning liability** (Note 14)
Assets (liabilities) held for sale	**148.4**	**(28.4)**

8. PROPERTY, PLANT AND EQUIPMENT

($ millions)	2022	2021
Development and production assets	**22,340.0**	23,402.9
Corporate assets	**126.2**	123.2
Property, plant and equipment at cost	**22,466.2**	23,526.1
Accumulated depletion, depreciation and impairment	**(14,736.8)**	(15,838.8)
Net carrying amount	**7,729.4**	7,687.3
Reconciliation of movements during the year		
Development and production assets		
Cost, beginning of year	**23,402.9**	23,584.1
Accumulated depletion and impairment, beginning of year	**(15,762.6)**	(19,265.2)
Net carrying amount, beginning of year	**7,640.3**	4,318.9
Net carrying amount, beginning of year	**7,640.3**	4,318.9
Acquisitions through business combinations	**66.0**	953.8
Additions	**741.9**	736.5
Dispositions	**(285.8)**	(243.7)
Transfers from exploration and evaluation assets	**80.8**	57.5
Reclassified as assets held for sale	**(148.4)**	—
Depletion	**(911.4)**	(708.5)
Impairment reversal	**428.6**	2,514.4
Foreign exchange	**76.2**	11.4
Net carrying amount, end of year	**7,688.2**	7,640.3
Cost, end of year	**22,340.0**	23,402.9
Accumulated depletion and impairment, end of year	**(14,651.8)**	(15,762.6)
Net carrying amount, end of year	**7,688.2**	7,640.3
Corporate assets		
Cost, beginning of year	**123.2**	120.7
Accumulated depreciation, beginning of year	**(76.2)**	(67.6)
Net carrying amount, beginning of year	**47.0**	53.1
Net carrying amount, beginning of year	**47.0**	53.1
Additions	**2.6**	2.5
Depreciation	**(8.5)**	(8.6)
Foreign exchange	**0.1**	—
Net carrying amount, end of year	**41.2**	47.0
Cost, end of year	**126.2**	123.2

At December 31, 2022, future development costs of $5.16 billion (December 31, 2021 - $4.58 billion) were included in costs subject to depletion.

Direct general and administrative costs capitalized by the Company during the year ended December 31, 2022 were $49.7 million (year ended December 31, 2021 - $45.1 million), including $14.7 million of share-based compensation costs (year ended December 31, 2021 - $14.3 million).

Impairment test of property, plant and equipment

The following table summarizes the total impairment reversal for the years ended December 31, 2022 and December 31, 2021:

($ millions)	**2022**	2021
Impairment reversal	**1,540.9**	2,514.4
Impairment	**(985.0)**	—
Impairment on assets held for sale	**(127.3)**	—
Impairment reversal	**428.6**	2,514.4

Assets Held for Sale

At December 31, 2022, the Company classified certain non-core assets in Alberta as held for sale. Immediately prior to classifying the assets as held for sale, the Company conducted a review of the assets' recoverable amounts and recorded an impairment loss of $71.3 million on PP&E as a component of net impairment reversal. The recoverable amount was determined based on the assets' fair value less costs of disposal and based on expected consideration. The Company also recorded an impairment loss of $56.0 million during the first quarter of 2022 related to assets held for sale at March 31, 2022. The assets were sold during the second quarter of 2022.

Q4 2022 Impairment

At December 31, 2022, there were no indicators of impairment or impairment reversal in the Alberta and Northern U.S. CGUs.

At December 31, 2022, the Company identified indicators that its Southeast Saskatchewan and Southwest Saskatchewan CGUs might be impaired. The increase in forecast costs in the current inflationary environment and the reallocation of forecast capital spending from Saskatchewan to Alberta and Northern U.S., since the last impairment test at March 31, 2022, were considered indicators of impairment. As a result, a test for impairment was conducted and the Company prepared estimates of future cash flows to determine the recoverable amount of the respective assets.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at December 31, 2022:

	2023 (1)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033** (3)
WTI ($US/bbl) (2)	80.33	78.50	76.95	77.61	79.16	80.74	82.36	84.00	85.69	87.40	89.15
Exchange Rate ($US/$Cdn)	0.745	0.765	0.768	0.772	0.775	0.775	0.775	0.775	0.775	0.775	0.775
WTI ($Cdn/bbl)	107.83	102.61	100.20	100.53	102.14	104.18	106.27	108.39	110.57	112.77	115.03
AECO ($Cdn/mmbtu) (2)	4.23	4.40	4.21	4.27	4.34	4.43	4.51	4.60	4.69	4.79	4.88

(1) Effective January 1, 2023.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2033 to the end of the reserve life. Exchange rates are assumed to be constant at 0.775.

At December 31, 2022, the Company determined that the carrying amount of the Southeast Saskatchewan and Southwest Saskatchewan CGUs exceeded their recoverable amount. The full amounts of the impairments were attributed to PP&E and, as a result, impairment losses of $985.0 million were recognized in net income. The impairment loss was due to the increase in forecast costs as a result of the high inflationary environment and the reallocation of forecast capital spending mentioned above.

At December 31, 2022, the after tax impairments that can be reversed in future periods for each CGU, net of depletion had no impairment loss been recognized in prior periods, were $1.49 billion for Southeast Saskatchewan, $1.09 billion for Southwest Saskatchewan, and nil for Alberta and Northern U.S.

The following table summarizes the impairment expense for the year ended December 31, 2022 by CGU:

CGU ($ millions, except %)	**Operating segment**	**Recoverable amount**	**Discount rate**	**Impairment**	**Impairment, net of tax**
Southeast Saskatchewan	Canada	2,868.3	15.00 %	564.5	424.4
Southwest Saskatchewan	Canada	1,356.6	15.00 %	420.5	316.1
Total impairment		4,224.9		985.0	740.5

Changes in any of the key judgments, such as a revision in reserves, changes in forecast benchmark commodity prices, foreign exchange rates, discount rates, capital or operating costs would impact the recoverable amounts of assets and any reversals or impairment charges would affect net income. The following sensitivities show the resulting impact on income before tax of the changes in discount rate, forecast benchmark commodity price and forecast operating cost estimates at December 31, 2022, with all other variables held constant:

CGU	Discount Rate		Commodity Prices		Operating Costs	
($ millions)	Increase 1%	Decrease 1%	Increase 5%	Decrease 5%	Increase 5%	Decrease 5%
Southeast Saskatchewan	(167.8)	185.2	349.4	(348.3)	(117.7)	118.7
Southwest Saskatchewan	(88.0)	97.3	185.6	(185.3)	(64.8)	65.0
Increase (decrease)	(255.8)	282.5	535.0	(533.6)	(182.5)	183.7

Q1 2022 Impairment Reversal

At March 31, 2022, the significant increase in forecast benchmark commodity prices and the increase in the Company's market capitalization since the last impairment test at June 30, 2021, were indicators of impairment reversal.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at March 31, 2022:

	2022 (1)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032** (3)
WTI ($US/bbl) (2)	94.17	84.05	75.38	74.41	75.90	77.42	78.97	80.55	82.16	83.80	85.48
Exchange Rate ($US/$Cdn)	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800
WTI ($Cdn/bbl)	117.71	105.06	94.23	93.01	94.88	96.78	98.71	100.69	102.70	104.75	106.85
AECO ($Cdn/mmbtu) (2)	5.18	4.18	3.38	3.34	3.41	3.48	3.54	3.61	3.69	3.76	3.84

(1) Effective April 1, 2022.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2032 to the end of the reserve life. Exchange rates are assumed to be constant at 0.800.

At March 31, 2022, the Company determined that the recoverable amount of the Southeast Saskatchewan, Southwest Saskatchewan, Alberta and Northern U.S. CGUs exceeded their carrying amount. The full amounts of the impairment reversals were attributed to PP&E and, as a result, impairment reversals of $1.54 billion were recognized in net income.

The following table summarizes the impairment reversal for the three months ended March 31, 2022 by CGU:

CGU ($ millions, except %)	**Operating segment**	**Recoverable amount**	**Discount rate**	**Impairment reversal**	**Impairment reversal, net of tax**
Southeast Saskatchewan	Canada	3,413.8	15.00 %	806.0	605.3
Southwest Saskatchewan	Canada	1,715.0	15.00 %	419.4	315.0
Alberta	Canada	2,567.1	15.00 %	244.2	183.4
Northern U.S.	U.S.	1,093.8	15.00 %	71.3	52.6
Total impairment reversal		8,789.7		1,540.9	1,156.3

The following sensitivities show the resulting impact on income before tax of the changes in discount rate and forecast benchmark commodity price estimates at March 31, 2022, with all other variables held constant:

CGU	Discount Rate		Commodity Prices	
($ millions)	Increase 1%	Decrease 1%	Increase 5%	Decrease 5%
Southeast Saskatchewan	(186.2)	204.8	367.6	(366.6)
Southwest Saskatchewan	(95.0)	104.6	201.1	(201.1)
Alberta	—	—	—	—
Northern U.S.	—	—	—	—
Increase (decrease)	(281.2)	309.4	568.7	(567.7)

2021 Impairment Reversal

At December 31, 2021, there were no indicators of impairment or impairment reversal.

At June 30, 2021, the significant increase in forecast benchmark commodity prices and the increase in the Company's market capitalization since the last impairment test at March 31, 2020 were indicators of impairment reversal.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at June 30, 2021:

	2021 (1)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031 (3)
WTI ($US/bbl) (2)	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	69.81	71.21	72.63
Exchange Rate ($US/$Cdn)	0.803	0.802	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800
WTI ($Cdn/bbl)	88.83	83.79	79.94	79.04	80.63	82.24	83.88	85.55	87.26	89.01	90.79
AECO ($Cdn/mmbtu) (2)	3.46	3.13	2.72	2.71	2.76	2.82	2.88	2.94	2.99	3.05	3.12

(1) Effective July 1, 2021.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2031 to the end of the reserve life. Exchange rates are assumed to be constant at 0.800.

The following table summarizes the impairment reversal for the six months ended June 30, 2021 by CGU:

CGU ($ millions, except %)	**Operating segment**	**Recoverable amount**	**Discount rate**	**Impairment reversal**	**Impairment reversal, net of tax**
Southeast Saskatchewan	Canada	2,941.0	15.00 %	917.7	688.1
Southwest Saskatchewan	Canada	1,422.6	15.00 %	604.1	453.0
Alberta (1)	Canada	1,911.9	15.00 %	555.6	416.6
Northern U.S.	U.S.	861.9	15.00 %	437.0	326.0
Total impairment reversal		7,137.4		2,514.4	1,883.7

(1) Previously referred to as the Southern Alberta CGU.

The following sensitivities show the resulting impact on income before tax of the changes in discount rate and forecast benchmark commodity price estimates at June 30, 2021, with all other variables held constant:

CGU	Discount Rate		Commodity Prices	
($ millions)	Increase 1%	Decrease 1%	Increase 5%	Decrease 5%
Southeast Saskatchewan	(181.1)	199.2	350.7	(349.9)
Southwest Saskatchewan	(89.1)	97.9	183.4	(182.7)
Alberta (1)	(89.4)	97.2	189.9	(190.3)
Northern U.S.	(57.1)	62.9	124.0	(124.1)
Increase (decrease)	(416.7)	457.2	848.0	(847.0)

(1) Previously referred to as the Southern Alberta CGU.

9. GOODWILL

($ millions)	**2022**	2021
Goodwill, beginning of year	**211.5**	223.3
Southeast Saskatchewan asset disposition	**—**	(10.6)
Saskatchewan Viking asset disposition	**(6.8)**	—
Other dispositions	**(0.8)**	(1.2)
Goodwill, end of year	**203.9**	211.5

Goodwill has been assigned to the Canadian operating segment.

Impairment test of goodwill

The impairment tests of goodwill compared the recoverable amount of the Company's PP&E and E&E to the carrying amount of the combined PP&E, E&E and goodwill at December 31, 2022 and December 31, 2021. The recoverable amount of the Company's PP&E and E&E was estimated using independent reserve evaluator forecast benchmark commodity prices, proved plus probable reserve estimates and management's estimate of the fair market value of undeveloped land. See to Note 6 - "Exploration and Evaluation Assets" and Note 8 - "Property, Plant and Equipment" for additional information. As a result of these tests, the Company concluded that the estimated recoverable amounts exceeded the carrying amounts and no impairments were recorded.

10. OTHER CURRENT LIABILITIES

($ millions)	**2022**	2021
Long-term compensation liability	**49.1**	40.6
Lease liability	**24.9**	25.5
Decommissioning liability	**41.6**	34.2
Other current liabilities	**115.6**	100.3

11. LONG-TERM DEBT

($ millions)	**2022**	2021
Bank debt	**—**	331.4
Senior guaranteed notes	**1,441.5**	1,638.8
Long-term debt	**1,441.5**	1,970.2
Long-term debt due within one year	**538.7**	278.1
Long-term debt due beyond one year	**902.8**	1,692.1

Bank debt

The Company has combined facilities of $2.36 billion, including a $2.26 billion syndicated unsecured credit facility with eleven banks and a $100.0 million unsecured operating credit facility with one Canadian chartered bank. The current maturity dates of the facilities is November 26, 2026. Both of these facilities constitute revolving credit facilities and are extendible annually.

The credit facilities and senior guaranteed notes have covenants which restrict the Company's ratio of senior debt to adjusted EBITDA to a maximum of 3.5:1.0, the ratio of total debt to adjusted EBITDA to a maximum of 4.0:1.0 and the ratio of senior debt to capital, adjusted for certain non-cash items as noted above, to a maximum of 0.55:1.0. The Company was in compliance with all debt covenants at December 31, 2022.

The Company had letters of credit in the amount of $1.8 million outstanding at December 31, 2022 (December 31, 2021 - $1.0 million).

Senior guaranteed notes

At December 31, 2022, the Company has senior guaranteed notes of US$921.0 million and Cdn$195.0 million outstanding. The notes are unsecured and rank *pari passu* with the Company's bank credit facilities and carry a bullet repayment on maturity. The senior guaranteed notes have financial covenants similar to those of the combined credit facilities described above. The Company's senior guaranteed notes are detailed below:

Principal ($ millions)	Coupon Rate	Hedged Equivalent (1) (Cdn$ millions)	Interest Payment Dates	Maturity Date	Financial statement carrying value **2022**	2021
Cdn$25.0	4.76 %	—	November 22 and May 22	May 22, 2022	**—**	25.0
US$200.0	4.00 %	—	November 22 and May 22	May 22, 2022	**—**	253.1
US$61.5	4.12 %	80.3	October 11 and April 11	April 11, 2023	**83.2**	77.8
Cdn$80.0	3.58 %	80.0	October 11 and April 11	April 11, 2023	**80.0**	80.0
Cdn$10.0	4.11 %	10.0	December 12 and June 12	June 12, 2023	**10.0**	10.0
US$270.0	3.78 %	274.7	December 12 and June 12	June 12, 2023	**365.5**	341.7
Cdn$40.0	3.85 %	40.0	December 20 and June 20	June 20, 2024	**40.0**	40.0
US$257.5	3.75 %	276.4	December 20 and June 20	June 20, 2024	**348.5**	325.9
US$82.0	4.30 %	107.0	October 11 and April 11	April 11, 2025	**111.0**	103.8
Cdn$65.0	3.94 %	65.0	October 22 and April 22	April 22, 2025	**65.0**	65.0
US$230.0	4.08 %	291.1	October 22 and April 22	April 22, 2025	**311.3**	291.1
US$20.0	4.18 %	25.3	October 22 and April 22	April 22, 2027	**27.0**	25.4
Senior guaranteed notes		1,249.8			**1,441.5**	1,638.8
Due within one year		445.0			**538.7**	278.1
Due beyond one year		804.8			**902.8**	1,360.7

(1) Includes underlying derivatives which fix the Company's foreign exchange exposure on its US dollar senior guaranteed notes.

Concurrent with the issuance of US$921.0 million senior guaranteed notes, the Company entered into cross currency swaps ("CCS") to manage the Company's foreign exchange risk. The CCS fix the US dollar amount of the individual tranches of notes for purposes of interest and principal repayments at a notional amount of $1.05 billion. See Note 25 - "Financial Instruments and Derivatives" for additional information.

12. LEASES

Right-of-use asset

($ millions)	Office [1]	Fleet Vehicles	Equipment	Total
Right-of-use asset at cost	121.9	28.5	11.1	161.5
Accumulated depreciation	(55.4)	(20.4)	(7.6)	(83.4)
Net carrying amount	66.5	8.1	3.5	78.1
Reconciliation of movements during the year				
Cost, beginning of year	121.6	25.2	11.7	158.5
Accumulated depreciation, beginning of year	(44.3)	(16.1)	(6.7)	(67.1)
Net carrying amount, beginning of year	77.3	9.1	5.0	91.4
Net carrying amount, beginning of year	77.3	9.1	5.0	91.4
Additions	—	3.2	0.7	3.9
Depreciation	(10.8)	(4.2)	(1.6)	(16.6)
Lease modification	—	—	(0.6)	(0.6)
Net carrying amount, end of year	66.5	8.1	3.5	78.1

(1) A portion of the Company's office space is subleased. During the year ended December 31, 2022, the Company recorded sublease income of $3.6 million (year ended December 31, 2021 - $5.4 million) as a component of other income.

Lease liability

($ millions)	**2022**	2021
Lease liability, beginning of year	**141.4**	156.5
Additions	**3.8**	5.9
Financing	**5.7**	6.5
Payments on lease liability	**(26.1)**	(27.7)
Other	**(0.7)**	0.2
Lease liability, end of year	**124.1**	141.4
Expected to be incurred within one year	**24.9**	25.5
Expected to be incurred beyond one year	**99.2**	115.9

Some leases contain variable payments that are not included within the lease liability as the payments are based on amounts determined by the lessor annually and not dependent on an index or rate. For the year ended December 31, 2022, variable lease payments of $1.5 million were included in general and administrative expenses relating to property tax payments on office leases (year ended December 31, 2021 - $1.5 million).

During the year ended December 31, 2022, the Company recorded $0.8 million in payments related to short-term leases and leases for low dollar value underlying assets in operating and general and administrative expenses (year ended December 31, 2021 - $0.6 million).

The undiscounted cash flows relating to the lease liability are as follows:

($ millions)	**December 31, 2022**
1 year	**25.5**
2 to 3 years	**41.3**
4 to 5 years	**33.6**
More than 5 years	**42.4**
Total (1)	**142.8**

(1) Includes both the principal and amounts representing interest.

13. OTHER LONG-TERM LIABILITIES

At December 31, 2022, the Company had a long-term compensation liability of $40.8 million (December 31, 2021 - $35.8 million) related to share-based compensation. See Note 23 - "Share-based Compensation" for additional information.

14. DECOMMISSIONING LIABILITY

($ millions)	**2022**	2021
Decommissioning liability, beginning of year	**918.8**	1,022.7
Liabilities incurred	**21.6**	13.6
Liabilities acquired through capital acquisitions	**3.4**	30.0
Liabilities disposed through capital dispositions	**(46.7)**	(220.3)
Liabilities settled (1)	**(43.1)**	(48.9)
Revaluation of acquired decommissioning liabilities (2)	**3.8**	36.1
Change in estimates	**(11.4)**	74.2
Change in discount and inflation rate estimates	**(163.0)**	(3.8)
Accretion	**19.2**	15.4
Reclassified as liabilities associated with assets held for sale	**(28.4)**	—
Foreign exchange	**1.3**	(0.2)
Decommissioning liability, end of year	**675.5**	918.8
Expected to be incurred within one year	**41.6**	34.2
Expected to be incurred beyond one year	**633.9**	884.6

(1) Includes $23.0 million received from government grant programs during the year ended December 31, 2022 (year ended December 31, 2021 - $28.7 million).

(2) These amounts relate to the revaluation of acquired decommissioning liabilities at the end of the period using a risk-free discount rate. At the date of acquisition, acquired decommissioning liabilities are fair valued.

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. The total future decommissioning liability was estimated by management based on the Company’s net ownership in all wells and facilities. This includes all estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of its total decommissioning liability to be $675.5 million at December 31, 2022 (December 31, 2021 - $918.8 million) based on total estimated undiscounted and uninflated cash flows to settle the obligation of $894.9 million (December 31, 2021 - $896.6 million). These obligations are expected to be settled through 2072, with the majority expected after 2049. The estimated cash flows have been discounted using a risk-free rate of 3.28 percent and a derived inflation rate of 2.09 percent (December 31, 2021 - risk-free rate of 1.68 percent and inflation rate of 1.82 percent).

15. SHAREHOLDERS' CAPITAL

Crescent Point has an unlimited number of common shares authorized for issuance.

	2022		2021	
	Number of shares	**Amount ($ millions)**	Number of shares	Amount ($ millions)
Common shares, beginning of year	**579,484,032**	**16,963.4**	530,035,922	16,707.6
Issued on capital acquisitions	**—**	**—**	50,000,000	264.5
Issued on redemption of restricted shares	**1,713,730**	**5.2**	2,109,241	8.5
Issued on exercise of stock options	**1,038,321**	**1.4**	155,869	0.3
Common shares repurchased for cancellation	**(31,347,100)**	**(294.2)**	(2,817,000)	(17.5)
Common shares, end of year	**550,888,983**	**16,675.8**	579,484,032	16,963.4
Cumulative share issue costs, net of tax	**—**	**(256.5)**	—	(256.5)
Total shareholders’ capital, end of year	**550,888,983**	**16,419.3**	579,484,032	16,706.9

Normal Course Issuer Bid ("NCIB")

On March 4, 2022, the Company announced the approval by the Toronto Stock Exchange of its notice to implement a NCIB. The NCIB allows the Company to purchase, for cancellation, up to 57,309,975 common shares, or 10 percent of the Company's public float, as at February 28, 2022. The NCIB commenced on March 9, 2022 and is due to expire on March 8, 2023.

During the year ended December 31, 2022, the Company purchased 31.3 million common shares for total consideration of $294.2 million. The total cost paid, including commissions and fees, was recognized directly as a reduction in shareholders' equity. Under the NCIB, all common shares purchased are cancelled.

16. DEFICIT

($ millions)	2022	2021
Accumulated earnings (deficit)	**(2,700.6)**	(4,184.0)
Accumulated gain on shares issued pursuant to DRIP [(1)] and SDP [(2)]	**8.4**	8.4
Accumulated tax effect on redemption of restricted shares	**15.8**	13.2
Accumulated dividends	**(7,886.9)**	(7,686.3)
Deficit	**(10,563.3)**	(11,848.7)

(1) Premium Dividend ™ and Dividend Reinvestment Plan – suspended in 2015.

(2) Share Dividend Plan – suspended in 2015.

17. CAPITAL MANAGEMENT

($ millions)	2022	2021
Long-term debt [(1)]	**1,441.5**	1,970.2
Adjusted working capital (surplus) deficiency [(2)]	**(95.1)**	201.6
Unrealized foreign exchange on translation of US dollar long-term debt	**(191.7)**	(166.8)
Net debt	**1,154.7**	2,005.0
Shareholders' equity	**6,493.4**	5,405.3
Total capitalization	**7,648.1**	7,410.3

(1) Includes current portion of long-term debt.

(2) Adjusted working capital (surplus) deficiency is calculated as accounts payable and accrued liabilities, dividends payable and long-term compensation liability net of equity derivative contracts, less cash, accounts receivable and prepaids and deposits, including deposit on acquisition.

The following table reconciles cash flow from operating activities to adjusted funds flow from operations for the year ended December 31, 2022 and December 31, 2021:

($ millions)	2022	2021
Cash flow from operating activities	**2,192.2**	1,495.8
Changes in non-cash working capital	**15.0**	(51.6)
Transaction costs	**5.1**	12.5
Decommissioning expenditures	**20.1**	20.2
Adjusted funds flow from operations	**2,232.4**	1,476.9

Crescent Point's objective for managing its capital structure is to maintain a strong balance sheet and capital base to provide financial flexibility, position the Company to fund future development projects and provide returns to shareholders.

Crescent Point manages its capital structure and short-term financing requirements using a measure not defined in IFRS, or standardized, the ratio of net debt to adjusted funds flow from operations. Net debt to adjusted funds flow from operations is used to measure the Company's overall debt position and to measure the strength of the Company's balance sheet and might not be comparable to similar financial measures disclosed by other issuers. Crescent Point's objective is to manage this metric to be well positioned to execute its business objectives during periods of volatile commodity prices. Crescent Point monitors this ratio and uses this as a key measure in capital allocation decisions including capital spending levels, returns to shareholders including dividends and share repurchases, and financing considerations. The Company's net debt to adjusted funds flow from operations ratio for the trailing four quarters at December 31, 2022 was 0.5 times (December 31, 2021 - 1.4 times).

Crescent Point is subject to certain financial covenants on its credit facilities and senior guaranteed notes agreements and was in compliance with all financial covenants as at December 31, 2022. See Note 11 - "Long-term Debt" for additional information regarding the Company's financial covenant requirements.

Crescent Point retains financial flexibility with significant liquidity on its credit facilities. The Company continuously monitors the commodity price environment and manages its counterparty exposure to mitigate credit losses and protect its balance sheet.

18. COMMODITY DERIVATIVE LOSSES

($ millions)	**2022**	2021
Realized losses	**(641.8)**	(360.8)
Unrealized gains (losses)	**168.4**	(128.1)
Commodity derivative losses	**(473.4)**	(488.9)

19. OTHER INCOME

($ millions)	**2022**	2021
Unrealized gain on long-term investments	**—**	3.1
Realized gain on sale of long-term investments	**—**	7.0
Gain on capital dispositions	**25.9**	58.4
Government grant for decommissioning expenditures	**23.0**	28.7
Sublease income	**3.6**	5.4
Other	**6.3**	(3.2)
Other income	**58.8**	99.4

20. INTEREST EXPENSE

($ millions)	**2022**	2021
Interest expense on long-term debt	**64.7**	88.9
Unrealized (gain) loss on interest derivative contracts	**(1.1)**	1.7
Interest expense	**63.6**	90.6

21. FOREIGN EXCHANGE GAIN (LOSS)

($ millions)	**2022**	2021
Realized gain on CCS - principal	**63.8**	—
Translation of US dollar long-term debt	**(94.3)**	37.0
Unrealized gain (loss) on CCS - principal and foreign exchange swaps	**4.4**	(34.4)
Other	**7.3**	1.8
Foreign exchange gain (loss)	**(18.8)**	4.4

22. INCOME TAXES

The provision for income taxes is as follows:

($ millions)	**2022**	2021
Current tax:		
Canada	**—**	—
United States	**—**	—
Current tax expense	**—**	—
Deferred tax expense (recovery):		
Canada	**415.1**	715.5
United States	**(27.2)**	84.2
Deferred tax expense	**387.9**	799.7
Income tax expense	**387.9**	799.7

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions, except percentages)	**2022**	2021
Net income before tax	**1,871.3**	3,163.8
Statutory income tax rate	**24.82 %**	25.16 %
Expected provision for income taxes	**464.5**	796.0
Change in corporate tax rates and tax rate variance	**1.6**	21.9
Tax rates in foreign jurisdictions	**2.1**	5.8
Restricted share bonus plan	**0.6**	(1.6)
Recognition of deferred tax assets	**(83.2)**	(70.7)
Derecognition of deferred tax assets	**—**	37.5
Non-taxable capital gains	**(0.2)**	(2.5)
Non-deductible disposition of goodwill	**1.9**	3.0
Other	**0.6**	10.3
Income tax expense	**387.9**	799.7

The composition of the net deferred income tax asset is as follows:

($ millions)	**2022**	2021
Deferred income tax assets	**278.8**	570.1
Deferred income tax liabilities	**(77.3)**	—
Net deferred income tax asset	**201.5**	570.1

The net deferred income tax assets (liabilities) are expected to be settled in the following periods:

($ millions)	**2022**	2021
Deferred income tax:		
To be settled within one year	**19.6**	60.1
To be settled beyond one year	**181.9**	510.0
Deferred income tax	**201.5**	570.1

The movement in deferred income tax assets (liabilities) are as follows:

($ millions)	At January 1, 2022	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings	**At December 31, 2022**
Deferred income tax assets:				
Property, plant and equipment	—	—	—	**—**
Decommissioning liability	229.6	—	(62.2)	**167.4**
Income tax losses carried forward	814.2	—	(69.6)	**744.6**
Risk management contracts	41.1	—	(39.0)	**2.1**
Lease liabilities	35.3	—	(4.6)	**30.7**
Other	19.5	19.3	(8.9)	**29.9**
	1,139.7	19.3	(184.3)	**974.7**
Deferred income tax liabilities:				
Property, plant and equipment	(533.4)	—	(209.7)	**(743.1)**
Risk management contracts	(13.4)	—	2.6	**(10.8)**
ROU asset	(22.8)	—	3.5	**(19.3)**
	(569.6)	—	(203.6)	**(773.2)**
Net deferred income tax assets (liabilities)	570.1	19.3	(387.9)	**201.5**

($ millions)	At January 1, 2021	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings	At December 31, 2021
Deferred income tax assets:				
Property, plant and equipment	248.9	—	(248.9)	—
Decommissioning liability	262.2	—	(32.6)	229.6
Income tax losses carried forward	833.1	—	(18.9)	814.2
Risk management contracts	11.6	—	29.5	41.1
Lease liabilities	40.1	—	(4.8)	35.3
Other	8.5	1.9	9.1	19.5
	1,404.4	1.9	(266.6)	1,139.7
Deferred income tax liabilities:				
Property, plant and equipment	—	—	(533.4)	(533.4)
Risk management contracts	(9.9)	—	(3.5)	(13.4)
ROU asset	(26.6)	—	3.8	(22.8)
	(36.5)	—	(533.1)	(569.6)
Net deferred income tax assets (liabilities)	1,367.9	1.9	(799.7)	570.1

The approximate amounts of tax pools available as at December 31, 2022 and 2021 are as follows:

($ millions)	**2022**	2021
Tax pools:		
Canada	**5,685.8**	7,012.5
United States	**3,025.2**	2,855.5
Total	**8,711.0**	9,868.0

Deferred tax assets are recognized to the extent of expected utilization of tax attributes, based on estimated undiscounted future cash flows included in the Company's independent reserve report.

The above tax pools include estimated Canadian non-capital losses carried forward of $1.36 billion (December 31, 2021 - $1.99 billion) that expire in the years 2034 through 2040, and U.S. net operating losses of $2.30 billion (December 31, 2021 - $2.22 billion) of which $1.55 billion will expire in the years 2033 through 2037, while the remaining $744.9 million will not expire. A deferred income tax asset has not been recognized for U.S. net operating losses of $507.2 million (December 31, 2021 - $861.0 million) or for other Canadian tax pools of $69.0 million (December 31, 2021 - $69.0 million) as there is not sufficient certainty regarding future utilization.

At December 31, 2022, a deferred tax asset has not been recognized in respect of temporary differences associated with investments in subsidiaries as it is not likely that the temporary differences will reverse in the foreseeable future. The deductible temporary differences associated with investments in subsidiaries is approximately $1.48 billion (December 31, 2021 - $1.72 billion).

The Company received notices of reassessment from the Canada Revenue Agency in 2014 and 2015 disallowing $149.3 million of tax pools and $12.6 million of investment tax credits relating to an acquired entity. The Company has filed notices of objections, however, the benefit of these tax pools and investment tax credits were derecognized in the year ended December 31, 2021 due to the uncertainty of being successful in defending its position. A $37.5 million deferred income tax expense was recognized in the year ended December 31, 2021 as a result of removing the tax pools.

23. SHARE-BASED COMPENSATION

The following table reconciles the number of restricted shares, ESVP awards, PSUs and DSUs for the year ended December 31, 2022:

	Restricted Shares	ESVP	PSUs (1)	DSUs
Balance, beginning of year	3,267,717	8,329,291	3,214,620	1,556,780
Granted	710,819	1,288,598	904,469	208,693
Redeemed	(1,718,906)	(3,691,820)	(1,405,913)	(19,594)
Forfeited	(14,892)	(651,591)	—	—
Balance, end of year	2,244,738	5,274,478	2,713,176	1,745,879

(1) Based on underlying units before any effect of performance multipliers.

The following table reconciles the number of restricted shares, ESVP awards, PSUs and DSUs for the year ended December 31, 2021:

	Restricted Shares	ESVP	PSUs [(1)]	DSUs
Balance, beginning of year	4,704,129	10,449,383	3,789,689	1,278,263
Granted	1,230,133	2,570,746	2,053,574	278,517
Redeemed	(2,146,716)	(3,417,496)	(2,221,058)	—
Forfeited	(519,829)	(1,273,342)	(407,585)	—
Balance, end of year	3,267,717	8,329,291	3,214,620	1,556,780

(1) Based on underlying units before any effect of performance multipliers.

The following table provides summary information regarding stock options outstanding as at December 31, 2022:

	Stock Options (number of units)	Weighted average exercise price ($)
Balance, beginning of year	5,839,464	4.04
Exercised	(1,446,571)	3.16
Forfeited	(398,610)	2.06
Expired	(105,153)	9.22
Balance, end of year	3,889,130	4.43

The following table summarizes information regarding stock options outstanding as at December 31, 2022:

Range of exercise prices ($)	Number of stock options outstanding	Weighted average remaining term for options outstanding (years)	Weighted average exercise price per share for options outstanding ($)	Number of stock options exercisable	Weighted average exercise price per share for options exercisable ($)
1.09 - 1.65	1,884,156	4.25	1.09	307,638	1.09
1.66 - 5.16	470,946	3.26	3.92	137,543	3.92
5.17 - 9.86	505,809	4.77	5.91	113,490	8.16
9.87 - 10.06	1,028,219	2.02	10.06	1,028,219	10.06
	3,889,130	3.61	4.43	1,586,890	7.65

The following table provides summary information regarding stock options outstanding as at December 31, 2021:

	Stock Options (number of units)	Weighted average exercise price ($)
Balance, beginning of year	5,940,871	3.92
Granted	534,264	5.23
Exercised	(261,486)	2.23
Forfeited	(285,047)	3.46
Expired	(89,138)	10.06
Balance, end of year	5,839,464	4.04

The volume weighted average trading price of the Company's common shares was $9.52 per share during the year ended December 31, 2022 (year ended December 31, 2021 - $5.14 per share).

For the year ended December 31, 2022, the Company calculated total share-based compensation of $77.3 million (year ended December 31, 2021 - $77.7 million), net of estimated forfeitures, of which $14.7 million was capitalized (year ended December 31, 2021 - $14.3 million).

At December 31, 2022, the current portion of long-term compensation liability of $49.1 million was included in other current liabilities (December 31, 2021 - $40.6 million) and $40.8 million was included in other long-term liabilities (December 31, 2021 - $35.8 million).

24. PER SHARE AMOUNTS

The following table summarizes the weighted average shares used in calculating net income per share:

	2022	2021
Weighted average shares – basic	**566,710,644**	569,203,428
Dilutive impact of share-based compensation	**4,357,422**	5,895,220
Weighted average shares – diluted	**571,068,066**	575,098,648

25. FINANCIAL INSTRUMENTS AND DERIVATIVES

The Company's financial assets and liabilities are comprised of cash, accounts receivable, derivative assets and liabilities, accounts payable and accrued liabilities, dividends payable and long-term debt.

Crescent Point's derivative assets and liabilities are transacted in active markets. The Company classifies the fair value of these transactions according to the following fair value hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 - Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 - Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.
- Level 3 - Values are based on prices or valuation techniques that are not based on observable market data.

Accordingly, Crescent Point's derivative assets and liabilities are classified as Level 2. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

Discussions of the fair values and risks associated with financial assets and liabilities, as well as summarized information related to derivative positions are detailed below:

a) Carrying amount and fair value of financial instruments

The fair value of cash, accounts receivable, accounts payable and accrued liabilities and dividends payable approximate their carrying amount due to the short-term nature of those instruments. The fair value of the amounts drawn on bank credit facilities is equal to its carrying amount as the facilities bear interest at floating rates and credit spreads that are indicative of market rates. These financial instruments are classified as financial assets and liabilities at amortized cost and are reported at amortized cost.

Crescent Point's derivative assets and liabilities are transacted in active markets, classified as financial assets and liabilities at fair value through profit or loss and fair valued at each period with the resulting gain or loss recorded in net income.

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair values as at December 31, 2022:

($ millions)	2022 Carrying Value	2022 Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Financial assets					
Derivatives	235.3	235.3	—	235.3	—
	235.3	235.3	—	235.3	—
Financial liabilities					
Derivatives	8.7	8.7	—	8.7	—
Senior guaranteed notes (1)	1,441.5	1,372.9	—	1,372.9	—
	1,450.2	1,381.6	—	1,381.6	—

(1) The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian dollars at the period end exchange rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair values as at December 31, 2021:

($ millions)	2021 Carrying Value	2021 Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Financial assets					
Derivatives	220.5	220.5	—	220.5	—
	220.5	220.5	—	220.5	—
Financial liabilities					
Derivatives	164.9	164.9	—	164.9	—
Senior guaranteed notes (1)	1,638.8	1,618.4	—	1,618.4	—
	1,803.7	1,783.3	—	1,783.3	—

(1) The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian dollars at the period end exchange rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

Derivative assets and liabilities

Derivative assets and liabilities arise from the use of derivative contracts. Crescent Point's derivative assets and liabilities are classified as Level 2 with values based on inputs including quoted forward prices for commodities, time value and volatility factors. Accordingly, the Company's derivative financial instruments are classified as fair value through profit or loss and are reported at fair value with changes in fair value recorded in net income.

The following table summarizes the fair value as at December 31, 2022 and the change in fair value for the year ended December 31, 2022:

($ millions)	Commodity (1)	Interest (2)	Foreign exchange (3)	Equity	Total
Derivative assets (liabilities), beginning of year	(154.4)	5.6	170.6	33.8	55.6
Unrealized change in fair value	168.4	1.1	4.4	(2.9)	171.0
Derivative assets, end of year	14.0	6.7	175.0	30.9	226.6
Derivative assets, end of year	22.6	6.7	175.1	30.9	235.3
Derivative liabilities, end of year	(8.6)	—	(0.1)	—	(8.7)

(1) Includes crude oil, crude oil differentials, propane, natural gas and natural gas differential contracts.

(2) Interest payments on CCS.

(3) Includes principal portion of CCS and foreign exchange contracts.

The following table summarizes the fair value as at December 31, 2021 and the change in fair value for the year ended December 31, 2021:

($ millions)	Commodity [(1)]	Interest [(2)]	Foreign exchange [(3)]	Equity	Total
Derivative assets (liabilities), beginning of year	(26.3)	7.3	205.0	11.0	197.0
Unrealized change in fair value	(128.1)	(1.7)	(34.4)	22.8	(141.4)
Derivative assets (liabilities), end of year	(154.4)	5.6	170.6	33.8	55.6
Derivative assets, end of year	5.4	5.7	175.6	33.8	220.5
Derivative liabilities, end of year	(159.8)	(0.1)	(5.0)	—	(164.9)

(1) Includes crude oil, crude oil differentials, propane, natural gas and natural gas differential contracts.

(2) Interest payments on CCS and interest derivative contracts.

(3) Includes principal portion of CCS and foreign exchange contracts.

Offsetting financial assets and liabilities

Financial assets and liabilities are only offset if the Company has the legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. The Company offsets derivative assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. The following table summarizes the gross asset and liability positions of the Company's financial derivatives by contract that are offset on the balance sheet as at December 31, 2022 and December 31, 2021:

			2022			2021
($ millions)	Asset	Liability	Net	Asset	Liability	Net
Gross amount	246.3	(19.7)	226.6	218.9	(163.3)	55.6
Amount offset	(11.0)	11.0	—	1.6	(1.6)	—
Net amount	235.3	(8.7)	226.6	220.5	(164.9)	55.6

b) Risks associated with financial assets and liabilities

The Company is exposed to financial risks from its financial assets and liabilities. The financial risks include market risk relating to commodity prices, interest rates, foreign exchange rates and equity price as well as credit and liquidity risk.

Commodity price risk

The Company is exposed to commodity price risk on crude oil and condensate, NGLs and natural gas revenues. To manage a portion of this risk, the Company has entered into various derivative agreements.

The following table summarizes the unrealized gains (losses) on the Company's commodity financial derivative contracts and the resulting impact on income before tax due to fluctuations in commodity prices or differentials, with all other variables held constant:

	Impact on Income Before Tax		Impact on Income Before Tax	
($ millions)	Year ended December 31, 2022		Year ended December 31, 2021	
	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Commodity price				
Crude oil and condensate	(40.3)	38.8	(148.5)	141.2
Natural gas	(3.1)	3.2	(1.1)	1.1
Differential				
Natural gas	2.6	(2.6)	1.9	(1.9)

Interest rate risk

The Company is exposed to interest rate risk on amounts drawn on its bank credit facilities to the extent of changes in market interest rates. At December 31, 2022, the Company was undrawn on its credit facilities and had no floating rate debt outstanding.

Foreign exchange risk

The Company is exposed to foreign exchange risk in relation to its US dollar denominated long-term debt, investment in U.S. subsidiaries and on a portion of its crude oil sales. Crescent Point utilizes foreign exchange derivatives to hedge its foreign exchange exposure on its US dollar denominated long-term debt. To reduce foreign exchange risk relating to crude oil sales, the Company utilizes a combination of foreign exchange swaps and fixed price WTI crude oil contracts that settle in Canadian dollars.

The following table summarizes the resulting unrealized gains (losses) impacting income before tax due to the respective changes in the period end and applicable foreign exchange rates, with all other variables held constant:

		Impact on Income Before Tax		Impact on Income Before Tax	
($ millions)	Exchange Rate	Year ended December 31, 2022		Year ended December 31, 2021	
Cdn$ relative to US$		Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
US dollar long-term debt	Period End	124.6	(124.6)	162.8	(162.8)
Cross currency swaps	Forward	(123.7)	123.7	(168.2)	168.2
Foreign exchange swaps	Forward	4.3	(4.3)	(0.9)	0.9

Equity price risk

The Company is exposed to equity price risk on its own share price in relation to certain share-based compensation plans detailed in Note 23 - “Share-based Compensation”. The Company has entered into total return swaps to mitigate its exposure to fluctuations in its share price by fixing the future settlement cost on a portion of it's cash settled plans.

The following table summarizes the unrealized gains (losses) on the Company's equity derivative contracts and the resulting impact on income before tax due to the respective changes in the applicable share price, with all other variables held constant:

	Impact on Income Before Tax		Impact on Income Before Tax	
($ millions)	Year ended December 31, 2022		Year ended December 31, 2021	
Share price	Increase 50%	Decrease 50%	Increase 50%	Decrease 50%
Total return swaps	26.8	(26.8)	27.4	(27.4)

Credit risk

The Company is exposed to credit risk in relation to its physical oil and gas sales, financial counterparty and joint venture receivables. A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. To mitigate credit risk associated with its physical sales portfolio, Crescent Point obtains financial assurances such as parental guarantees, letters of credit, prepayments and third party credit insurance. Including these assurances, approximately 98 percent of the Company's oil and gas sales are with entities considered investment grade.

At December 31, 2022, approximately 4 percent (December 31, 2021 - 3 percent) of the Company's accounts receivable balance was outstanding for more than 90 days and the Company's average expected credit loss was 0.93 percent (December 31, 2021 - 0.92 percent) on a portion of the Company’s accounts receivable balance relating to joint venture receivables.

Liquidity risk

The Company manages its liquidity risk through managing its capital structure and continuously monitoring forecast cash flows and available credit under existing banking facilities as well as other potential sources of capital.

At December 31, 2022, the Company had available unused borrowing capacity on bank credit facilities of approximately $2.36 billion as well as cash of $289.9 million.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2022, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Accounts payable and accrued liabilities	448.2	—	—	—	448.2
Dividends payable	99.4	—	—	—	99.4
Derivative liabilities (1)	12.6	—	—	—	12.6
Senior guaranteed notes (2)	486.6	816.2	26.9	—	1,329.7

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS related to the senior guaranteed notes, which fix the amounts due in Canadian dollars.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2021, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Accounts payable and accrued liabilities	450.7	—	—	—	450.7
Dividends payable	43.5	—	—	—	43.5
Derivative liabilities (1)	249.0	1.1	0.3	—	250.4
Senior guaranteed notes (2)	280.3	829.2	474.6	25.9	1,610.0
Bank credit facilities (3)	11.7	23.5	346.3	—	381.5

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS and foreign exchange swap related to the senior guaranteed notes, which fix the amounts due in Canadian dollars.

(3) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2021 and includes undiscounted cash outflows pursuant to the CCS related to LIBOR loans.

c) Derivative contracts

The following is a summary of the derivative contracts in place as at December 31, 2022:

Financial WTI Crude Oil Derivative Contracts – Canadian Dollar (1)

	Swap		Collar			Three-way Collar			
Term	Volume (bbls/d)	Average Price ($/bbl)	Volumes (bbls/d)	Average Sold Call Price ($/bbl)	Average Bought Put Price ($/bbl)	Volume (bbls/d)	Average Sold Call Price ($/bbl)	Average Bought Put Price ($/bbl)	Average Sold Put Price ($/bbl)
2023	1,356	90.04	10,586	114.99	101.39	616	118.11	96.00	76.00

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial AECO Natural Gas Derivative Contracts – Canadian Dollar (1)

	Swap		Collar		
Term	Volume (GJ/d)	Average Price ($/GJ)	Volume (GJ/d)	Average Sold Call Price ($/GJ)	Average Bought Put Price ($/GJ)
2023	21,605	4.68	7,397	10.21	4.48
2024 January - March	10,000	5.13	—	—	—

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial NYMEX Natural Gas Differential Derivative Contracts – US Dollar (1)

Term	Volume (mmbtu/d)	Contract	Basis	Fixed Differential (US$/mmbtu)
January 2023 - March 2025	17,500	Basis Swap	AECO	(0.94)

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial Cross Currency Derivative Contracts

Term	Contract	Receive Notional Principal (US$ millions)	Fixed Rate (US%)	Pay Notional Principal (Cdn$ millions)	Fixed Rate (Cdn%)
January 2023 - April 2023	Swap	61.5	4.12	80.3	3.71
January 2023 - June 2023	Swap	270.0	3.78	274.7	4.32
January 2023 - June 2024	Swap	257.5	3.75	276.4	4.03
January 2023 - April 2025	Swap	82.0	4.30	107.0	3.98
January 2023 - April 2025	Swap	230.0	4.08	291.1	4.13
January 2023 - April 2027	Swap	20.0	4.18	25.3	4.27

Financial Foreign Exchange Forward Derivative Contracts					
Settlement Date	Contract	Receive Currency	Receive Notional Principal ($ millions)	Pay Currency	Pay Notional Principal ($ millions)
January 2023	Swap	US$	15.0	Cdn$	20.5
January 2023	Swap [(1)]	Cdn$	63.9	US$	47.0

(1) Based on an average floating exchange rate.

Financial Equity Derivative Contracts			
Term	Contract	Notional Principal ($ millions)	Number of shares
January 2023 - April 2023	Swap	11.9	4,060,760
January 2023 - April 2024	Swap	7.2	1,103,860
January 2023 - April 2025	Swap	3.6	386,014

26. RELATED PARTY TRANSACTIONS

Compensation of key management personnel

Key management personnel of the Company include its directors and executive officers. In 2022, the Company recorded $6.1 million (2021 - $6.1 million) relating to compensation of key management personnel and nil (2021 - $2.8 million) for severance relating to key management personnel. In 2022, share-based compensation costs relating to compensation of key management personnel and severance were $24.2 million (2021 - $23.4 million) and nil (2021 - $1.8 million), respectively.

27. COMMITMENTS

At December 31, 2022, the Company had contractual obligations and commitments as follows:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Operating (1)	11.7	15.7	9.8	11.9	49.1
Gas processing	64.6	105.4	88.5	291.8	550.3
Transportation	43.3	74.8	41.5	40.1	199.7
Capital	7.3	—	—	—	7.3
Total contractual commitments (2)	126.9	195.9	139.8	343.8	806.4

(1) Includes operating costs on the Company's office space, net of $18.1 million recoveries from subleases.

(2) Excludes contracts accounted for under IFRS 16. See Note 12 - "Leases" for additional information.

28. SIGNIFICANT SUBSIDIARIES

The Company has the following significant subsidiaries, each owned 100% directly and indirectly, at December 31, 2022:

Subsidiary Name	**Country of Formation**
Crescent Point Resources Partnership	Canada
Crescent Point Holdings Ltd.	Canada
Crescent Point Energy U.S. Corp.	United States of America
Crescent Point U.S. Holdings Corp.	United States of America

29. SUPPLEMENTAL DISCLOSURES

Comprehensive income statement presentation

The Company’s statements of comprehensive income are prepared primarily by nature of expense, with the exception of compensation expenses which are included in the operating, general and administrative and share-based compensation line items, as follows:

($ millions)	**2022**	2021
Operating	**61.1**	59.7
General and administrative	**60.8**	65.2
Share-based compensation	**36.2**	53.7
Total compensation expenses	**158.1**	178.6

Cash flow statement presentation

($ millions)	**2022**	2021
Operating activities		
Changes in non-cash working capital:		
Accounts receivable	**(11.3)**	(111.8)
Prepaids and deposits	**(13.9)**	15.3
Accounts payable and accrued liabilities	**(3.5)**	99.0
Other current liabilities	**8.6**	30.6
Other long-term liabilities	**5.1**	18.5
	(15.0)	51.6
Investing activities		
Changes in non-cash working capital:		
Accounts receivable	**0.2**	(2.1)
Other long-term receivable	**—**	9.3
Accounts payable and accrued liabilities	**(7.6)**	41.8
	(7.4)	49.0
Financing activities		
Changes in non-cash working capital:		
Prepaids and deposits	**(44.2)**	—
Accounts payable and accrued liabilities	**4.0**	—
Dividends payable	**55.9**	42.2
	15.7	42.2

Supplementary financing cash flow information

The Company's reconciliation of cash flow from financing activities is outlined in the table below:

($ millions)	Dividends payable	Long-term debt (1)	Lease liability (2)
December 31, 2020	1.3	2,259.6	156.5
Changes from cash flow from financing activities:			
Decrease in bank debt, net		(34.6)	
Repayment of senior guaranteed notes		(217.6)	
Dividends paid	(5.6)		
Payments on principal portion of lease liability			(21.2)
Non-cash changes:			
Dividends declared	47.8		
Additions			5.9
Other			0.2
Foreign exchange		(37.2)	
December 31, 2021	43.5	1,970.2	141.4
Changes from cash flow from financing activities:			
Decrease in bank debt, net		**(338.5)**	
Repayment of senior guaranteed notes		**(281.8)**	
Realized gain on cross currency swap maturity		**63.8**	
Dividends paid	**(144.7)**		
Payments on principal portion of lease liability			**(20.4)**
Non-cash changes:			
Dividends declared	**200.6**		
Additions			**3.8**
Other			**(0.7)**
Foreign exchange		**27.8**	
December 31, 2022	**99.4**	**1,441.5**	**124.1**

(1) Includes current portion of long-term debt.

(2) Includes current portion of lease liability.

30. GEOGRAPHICAL DISCLOSURE

The following table reconciles oil and gas sales by country:

($ millions) (1)	**2022**	2021
Canada		
Crude oil and condensate sales	**3,319.1**	2,361.8
NGL sales	**224.8**	213.5
Natural gas sales	**303.1**	160.0
Total Canada	**3,847.0**	2,735.3
U.S.		
Crude oil and condensate sales	**553.3**	381.9
NGL sales	**55.2**	61.0
Natural gas sales	**37.6**	28.3
Total U.S.	**646.1**	471.2
Total oil and gas sales	**4,493.1**	3,206.5

(1) Oil and gas sales are reported before realized derivatives.

The following table reconciles non-current assets by country:

($ millions)	**2022**	2021
Canada	**6,977.9**	7,551.0
U.S.	**1,519.3**	1,209.3
Total	**8,497.2**	8,760.3

31. SUBSEQUENT EVENTS

Acquisition of Kaybob Duvernay Assets

On January 11, 2023, Crescent Point completed the acquisition of certain Kaybob Duvernay assets in Alberta for cash consideration of $370.6 million, including closing adjustments, which is expected to be allocated substantially to PP&E and E&E. Cash consideration was funded primarily through cash on hand and included a deposit on acquisition of $18.7 million.

Directors

Barbara Munroe, Chair [6]

James Craddock [2] [3] [5]

John Dielwart [3] [4]

Ted Goldthorpe [1] [5]

Mike Jackson [1] [5]

Jennifer Koury [2] [5]

Francois Langlois [1] [3] [4]

Myron Stadnyk [2] [3] [4]

Mindy Wight [1] [2]

Craig Bryksa [4]

[1] Member of the Audit Committee of the Board of Directors

[2] Member of the Human Resources and Compensation Committee of the Board of Directors

[3] Member of the Reserves Committee of the Board of Directors

[4] Member of the Environment, Safety and Sustainability Committee of the Board of Directors

[5] Member of the Corporate Governance and Nominating Committee

[6] Chair of the Board serves in an *ex officio* capacity on each Committee

Officers

Craig Bryksa
President and Chief Executive Officer

Ken Lamont
Chief Financial Officer

Ryan Gritzfeldt
Chief Operating Officer

Mark Eade
Senior Vice President, General Counsel and Corporate Secretary

Garret Holt
Senior Vice President, Corporate Development

Michael Politeski
Senior Vice President, Finance and Treasurer

Shelly Witwer
Senior Vice President, Business Development

Justin Foraie
Vice President, Engineering and Marketing

Head Office

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Tel: (403) 693-0020
Fax: (403) 693-0070

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Norton Rose Fulbright Canada LLP
Calgary, Alberta

Evaluation Engineers

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Investors are encouraged to contact Crescent Point's Registrar and Transfer Agent for information regarding their security holdings:

Computershare Trust Company of Canada
600, 530 - 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Tel: (403) 267-6800

Stock Exchanges

Toronto Stock Exchange - TSX
New York Stock Exchange - NYSE

Stock Symbol

CPG

Investor Contacts

Shant Madian
Vice President, Capital Markets
(403) 693-0020

Sarfraz Somani
Manager, Investor Relations
(403) 693-0020

Exhibit 99.3

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is dated March 1, 2023 and should be read in conjunction with the audited consolidated financial statements for the period ended December 31, 2022 for a full understanding of the financial position and results of operations of Crescent Point Energy Corp. (the "Company" or "Crescent Point").

The audited consolidated financial statements and comparative information for the year ended December 31, 2022 have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB").

STRUCTURE OF THE BUSINESS

The principal undertaking of Crescent Point is to carry on the business of acquiring, developing and holding interests in petroleum and natural gas properties and assets related thereto through a general partnership and wholly owned subsidiaries. Amounts in this MD&A are in Canadian dollars unless noted otherwise. References to "US$" and "US dollars" are to United States ("U.S.") dollars.

Overview

Crescent Point's 2022 results demonstrate strong operational execution, a strengthened balance sheet and continued commitment to shareholder returns. Strong WTI prices supported the Company's positive financial results, with adjusted funds flow from operations of $2.23 billion, net income of $1.48 billion and $1.15 billion of excess cash flow during 2022. The Company reduced net debt by $850.3 million, exiting the year with a net debt balance of approximately $1.15 billion and a net debt to adjusted funds flow from operations ratio of 0.5 times. The Company recorded a net impairment reversal of $428.6 million for the year, which was primarily attributable to higher forecast commodity prices partially offset by higher forecast costs.

The Company achieved its 2022 guidance with average annual production of 132,282 boe/d (guidance of 132,000 boe/d), annual operating expenses of $713.1 million or $14.77/boe (guidance of $14.75/boe), and development capital expenditures of $956.1 million (guidance of $950.0 million) to drill 206.6 net wells. The inflationary environment in 2022 resulted in higher expenses and capital costs compared to 2021 levels.

The Company continued to focus its asset portfolio and further enhance its long-term sustainability in 2022. In August, the Company acquired certain Kaybob Duvernay assets for cash consideration of $87.0 million, strengthening its position in this core area. Subsequent to year end, the Company closed the acquisition of additional Kaybob Duvernay assets for cash consideration of $370.6 million. These strategic transactions increased the Company's drilling inventory in the Kaybob Duvernay to over 20 years. The Company also closed non-core asset dispositions for total cash consideration of $283.6 million during 2022.

In July 2022, the Company achieved its near-term debt target and released its updated return of capital framework targeting the return of up to 50 percent of discretionary excess cash flow, in addition to its base dividend, through a combination of share repurchases and dividends. During the year, the Company repurchased for cancellation 31.3 million common shares for aggregate consideration of $294.2 million, and declared $0.3600 per share in dividends to shareholders. In 2022, the Company raised its quarterly cash dividend three times, from an initial quarterly dividend of $0.0450 per share to a quarterly dividend of $0.1000 per share payable on April 3, 2023.

Crescent Point's 2023 guidance includes annual average production of 138,000 - 142,000 boe/d and development capital expenditures of $1.00 - $1.10 billion. Based on current forecast commodity prices, the Company expects to generate strong returns and cash flow to provide continued returns to shareholders.

Adjusted funds flow from operations, net debt, net debt to adjusted funds flow from operations and excess cash flow are specified financial measures that do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Results of Operations

Production

	2022	2021	% Change
Crude oil and condensate (bbls/d)	**91,679**	95,839	(4)
NGLs (bbls/d)	**17,039**	17,769	(4)
Natural gas (mcf/d)	**141,384**	114,452	24
Total (boe/d)	**132,282**	132,683	—
Crude oil and liquids (%)	**82**	86	(4)
Natural gas (%)	**18**	14	4
Total (%)	**100**	100	—

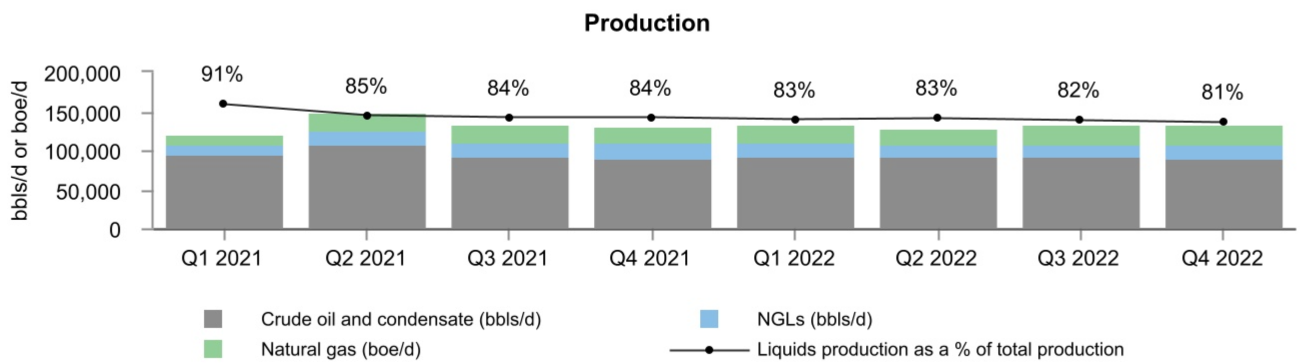
The following is a summary of Crescent Point's production by area:

Production By Area (boe/d)	2022	2021	% Change
Saskatchewan	**68,986**	80,893	(15)
Alberta	**44,766**	31,739	41
North Dakota	**18,530**	20,051	(8)
Total	**132,282**	132,683	—

Total production averaged 132,282 boe/d during 2022 compared to 132,683 boe/d in 2021. The Company's production by area has varied as production growth in the Kaybob Duvernay area was offset by non-core asset dispositions in Saskatchewan.

The Company's weighting to crude oil and liquids production in 2022 decreased by 4 percent. The decrease was primarily due to higher natural gas production as a result of production growth in the Kaybob Duvernay area and the dispositions of non core oil-weighted conventional assets in Southeast Saskatchewan as well as in the Saskatchewan Viking resource play.

Exhibit 1



Marketing and Prices

Average Selling Prices [(1)]	2022	2021	% Change
Crude oil and condensate ($/bbl)	**115.72**	78.43	48
NGLs ($/bbl)	**45.02**	42.33	6
Natural gas ($/mcf)	**6.60**	4.51	46
Total ($/boe)	**93.06**	66.21	41

(1) The average selling prices reported are before realized commodity derivatives and transportation.

Benchmark Pricing	2022	2021	% Change
Crude Oil Prices			
WTI crude oil (US$/bbl) [(1)]	**94.23**	67.96	39
WTI crude oil (Cdn$/bbl)	**122.54**	85.16	44
Crude Oil and Condensate Differentials			
LSB crude oil (Cdn$/bbl) [(2)]	**(4.42)**	(5.01)	(12)
FOS crude oil (Cdn$/bbl) [(3)]	**(21.81)**	(12.89)	69
UHC crude oil (US$/bbl) [(4)]	**3.94**	(0.05)	(7,980)
C5+ condensate (Cdn$/bbl) [(5)]	**(0.64)**	0.35	(283)
Natural Gas Prices			
AECO daily spot natural gas (Cdn$/mcf) [(6)]	**5.31**	3.62	47
AECO monthly index natural gas (Cdn$/mcf)	**5.56**	3.57	56
NYMEX natural gas (US$/mmbtu) [(7)]	**6.64**	3.85	72
Foreign Exchange Rate			
Exchange rate (US$/Cdn$)	**0.769**	0.798	(4)

(1) WTI refers to the West Texas Intermediate crude oil price.

(2) LSB refers to the Light Sour Blend crude oil price.

(3) FOS refers to the Fosterton crude oil price, which typically receives a premium to the Western Canadian Select price.

(4) UHC refers to the Sweet at Clearbrook crude oil price.

(5) C5+ condensate refers to the Canadian C5+ condensate index.

(6) AECO refers to the Alberta Energy Company natural gas price.

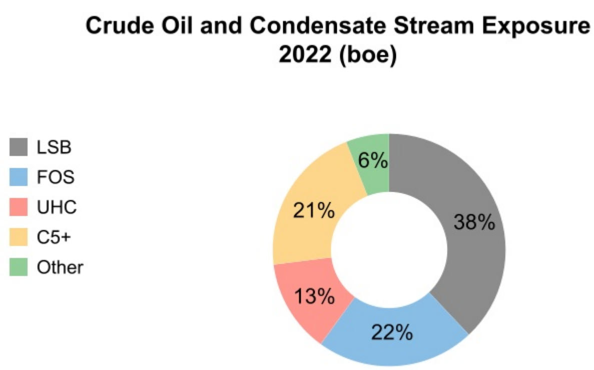
(7) NYMEX refers to the New York Mercantile Exchange natural gas price.

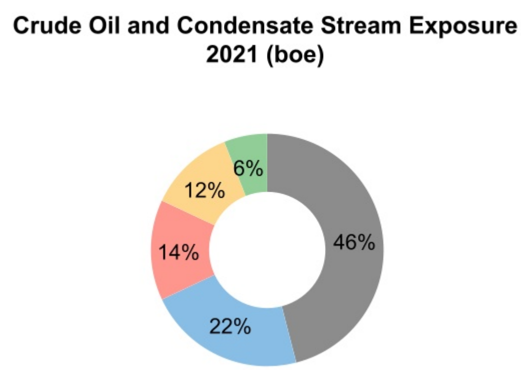
Benchmark crude oil prices strengthened in the first half of 2022, primarily due to the recovery in global demand from the impacts of the COVID-19 pandemic and the impact of the Russian invasion of Ukraine. OPEC did not sufficiently increase production to meet growing demand which put additional pressure on global inventory levels. The increase in demand was partially offset by releases of crude oil from the Strategic Petroleum Reserve ("SPR") by the U.S. government, which increased supply. In the second half of the year WTI prices fell primarily due to heightened fears of a global recession and its effect on capital markets.

U.S. natural gas prices strengthened in 2022, due to the conflict in Ukraine and the call on U.S. natural gas to meet European demand. The recovery from the pandemic also spurred further demand for natural gas and incremental strength in global gas prices.

Alberta natural gas prices were higher than the previous year due to the increased global demand for natural gas; however, reduced takeaway capacity from pipeline maintenance put downward pressure on prices and resulted in a wider AECO differential to NYMEX relative to 2021.

Exhibit 2





LSB and UHC crude oil differentials improved in 2022 compared to the same periods in 2021, primarily due to planned maintenance of oil sands upgraders, which removed significant light oil supply from the market. FOS crude oil differentials widened in 2022, primarily due to discounted Western Canadian Select ("WCS") crude oil pricing in the U.S. Gulf Coast as a result of the SPR releases. WCS crude oil differentials were also impacted by a fire at the BP Toledo refinery in September 2022 which resulted in a full shutdown and reduced heavy oil demand in the Petroleum Administration for Defense Districts Midwest.

Condensate differentials weakened slightly in 2022, primarily due to depressed naphtha pricing in the U.S. Gulf Coast, which competes directly with Canadian C5+.

In 2022, the Company's average selling price for crude oil and condensate increased 48 percent, primarily due to a 44 percent increase in the Cdn$ WTI benchmark price.

Crescent Point's corporate crude oil and condensate differential relative to Cdn$ WTI in 2022 was $6.82 per bbl compared to $6.73 per bbl in 2021. The slightly wider differential was driven by weaker FOS and C5+ differentials, partially offset by stronger LSB and UHC price differentials.

In 2022, the Company's average selling price for NGLs remained relatively consistent with 2021.

The Company's average selling price for natural gas in 2022 increased 46 percent, primarily as a result of the increases in the AECO daily and NYMEX benchmark prices. The Company's Canadian gas production generally trades at a slight premium to AECO pricing.

Exhibit 3

Crude Oil and Condensate Prices - Canadian Operations

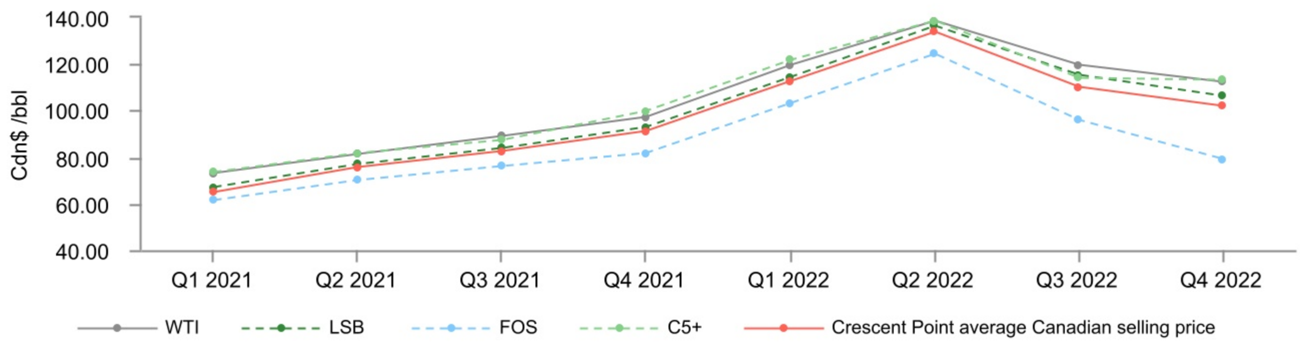
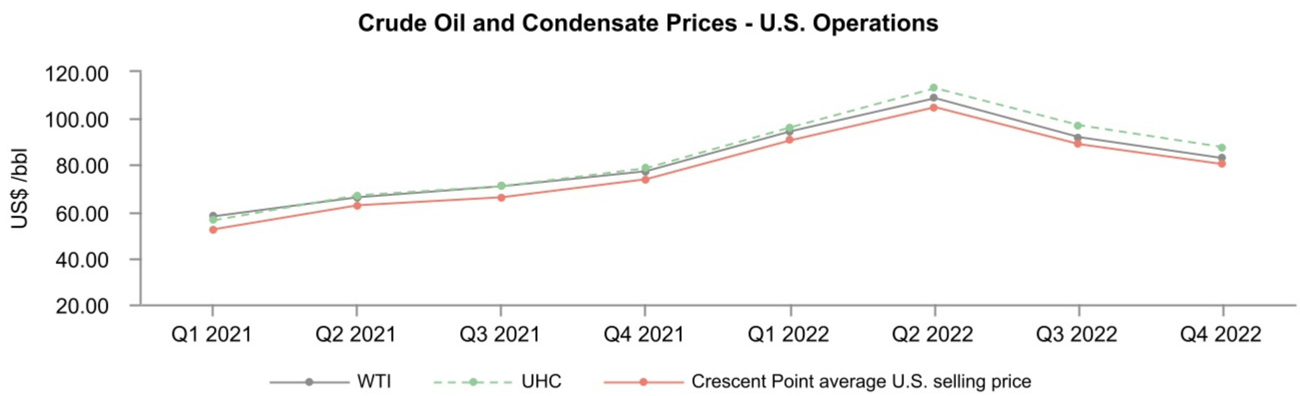


Exhibit 4



Commodity Derivatives

Management of cash flow variability is an integral component of Crescent Point's business strategy. Crescent Point regularly monitors changing business and market conditions while executing its strategic risk management program. Crescent Point proactively manages the risk exposure inherent in movements in the price of crude oil, propane, natural gas, interest rates, the Company's share price and the US/Cdn dollar exchange rate through the use of derivatives with investment-grade counterparties.

The Company's crude oil and NGL derivatives are referenced to WTI and Conway C3, respectively. The Company's natural gas derivatives are referenced to NYMEX and the AECO monthly index. Crescent Point utilizes a variety of derivatives, including swaps, collars and put options, to protect against downward commodity price movements while also providing the opportunity for some upside participation during periods of rising prices. This reduces the volatility of the selling price of crude oil and natural gas production and provides a measure of stability to the Company's cash flow. See Note 25 – "Financial Instruments and Derivatives" in the audited consolidated financial statements for the period ended December 31, 2022 for additional information on the Company's derivatives.

The following is a summary of the realized commodity derivative gains and losses:

($ millions, except volume amounts)	**2022**	2021	% Change
Average crude oil volumes hedged (bbls/d) [(1)]	**44,229**	48,432	(9)
Crude oil realized derivative loss [(1)]	**(647.3)**	(351.1)	84
per bbl	**(19.34)**	(10.04)	93
Average NGL volumes hedged (bbls/d)	**416**	210	98
NGL realized derivative loss	**(1.1)**	(0.7)	57
per bbl	**(0.18)**	(0.11)	64
Average natural gas volumes hedged (GJ/d) [(2)] [(3)]	**31,233**	35,397	(12)
Natural gas realized derivative gain (loss) [(3)]	**6.6**	(9.0)	(173)
per GJ	**0.13**	(0.22)	(159)
Average barrels of oil equivalent hedged (boe/d) [(1)] [(3)]	**49,579**	54,234	(9)
Total realized commodity derivative losses [(1)] [(3)]	**(641.8)**	(360.8)	78
per boe	**(13.29)**	(7.45)	78

(1) The crude oil realized derivative loss for the year ended December 31, 2022 and December 31, 2021 includes the realized derivative gains and losses on financial crude oil price differential contracts. The average crude oil volumes hedged and average barrels of oil equivalent hedged do not include the hedged volumes related to financial crude oil price differential contracts.

(2) GJ/d is defined as gigajoules per day.

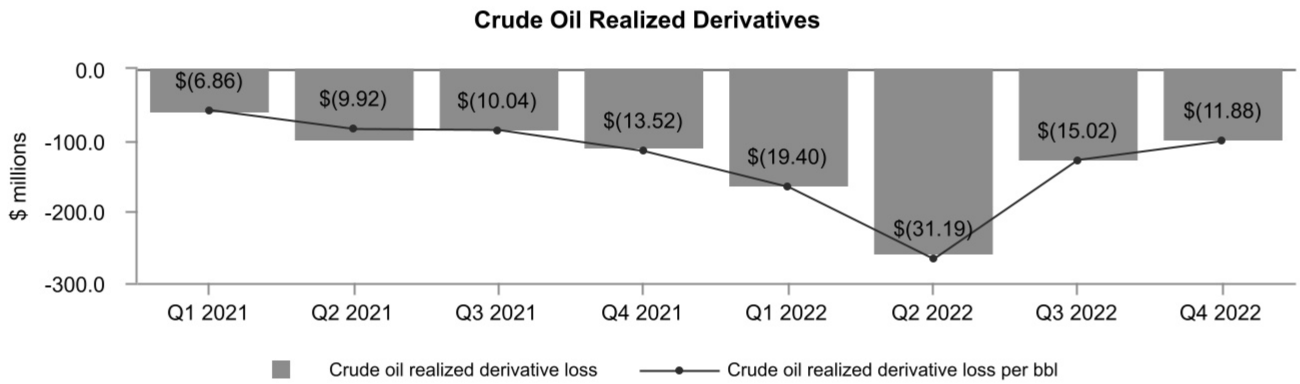
(3) The natural gas derivative gain for the year ended December 31, 2022 includes the realized derivative gains on financial natural gas price differential contracts. The average natural gas volumes hedged and average barrels of oil equivalent hedged do not include the hedged volumes related to financial natural gas price differentials contracts.

The Company's realized derivative losses for crude oil were $647.3 million for the year ended December 31, 2022, compared to $351.1 million in 2021. The increased realized derivative losses were primarily attributable to the increase in the Cdn$ WTI benchmark price.

The Company's realized derivative losses for NGLs were $1.1 million for the year ended December 31, 2022, compared to $0.7 million in 2021. The increased derivative losses in 2022 were primarily attributable to the higher average hedged volumes.

Crescent Point's realized derivative gains for natural gas were $6.6 million for the year ended December 31, 2022, compared to losses of $9.0 million in 2021. The gains relate to the Company's financial natural gas basis differential contracts as a result of the wider AECO to NYMEX differential. The derivative gains in 2022 on basis differential contracts were partially offset by losses on AECO swap contracts.

Exhibit 5



The following is a summary of the Company's unrealized commodity derivative gains (losses):

($ millions)	**2022**	2021	% Change
Crude oil	**145.6**	(128.6)	(213)
NGL	**(0.1)**	1.9	(105)
Natural gas	**22.9**	(1.4)	(1,736)
Total unrealized commodity derivative gains (losses)	**168.4**	(128.1)	(231)

For the year ended December 31, 2022, the Company recognized a total unrealized derivative gain of $168.4 million on its commodity contracts compared to a total unrealized derivative loss of $128.1 million in 2021. The unrealized crude oil derivative gain in 2022 was primarily attributable to the maturity of out-of-the-money derivative contracts, partially offset by the increase in the Cdn$ WTI forward benchmark prices at December 31, 2022 compared to December 31, 2021. The unrealized gain on natural gas derivative contracts in 2022 was primarily due to the decrease in the AECO monthly index forward benchmark price relative to the Company's average hedge price and a wider AECO differential to NYMEX.

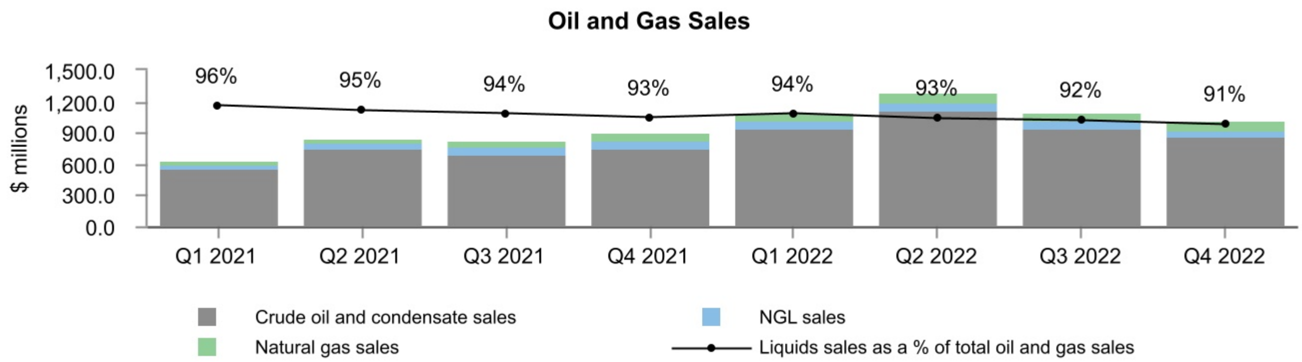
Oil and Gas Sales

($ millions) [1]	**2022**	2021	% Change
Crude oil and condensate sales	**3,872.4**	2,743.7	41
NGL sales	**280.0**	274.5	2
Natural gas sales	**340.7**	188.3	81
Total oil and gas sales	**4,493.1**	3,206.5	40

(1) Oil and gas sales are reported before realized commodity derivatives.

Total oil and gas sales increased by 40 percent in 2022 compared to 2021. Crude oil and condensate sales increased 41% due to the impact of higher realized pricing, partially offset by lower production volumes. Natural gas sales increased 81% due to higher realized pricing and increased natural gas production volumes.

Exhibit 6

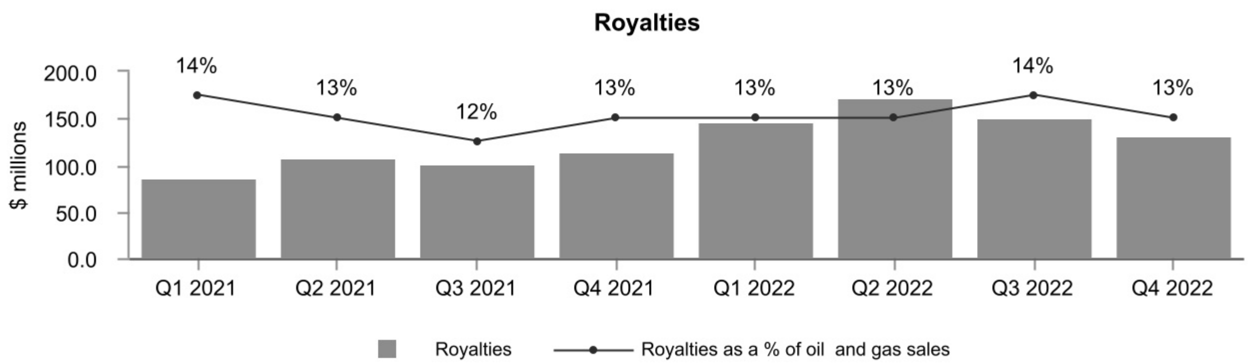

Oil and Gas Sales
$ millions
1,500.0
1,200.0
900.0
600.0
300.0
0.0
96%
95%
94%
93%
94%
93%
92%
91%
Q1 2021
Q2 2021
Q3 2021
Q4 2021
Q1 2022
Q2 2022
Q3 2022
Q4 2022
Crude oil and condensate sales
NGL sales
Natural gas sales
Liquids sales as a % of total oil and gas sales

Royalties

($ millions, except % and per boe amounts)	**2022**	2021	% Change
Royalties	**600.9**	408.8	47
As a % of oil and gas sales	**13**	13	—
Per boe	**12.45**	8.44	48

Royalties increased 47 percent in 2022 compared to 2021 due to the increase in oil and gas sales. Royalties as a percentage of oil and gas sales remained consistent in 2022 compared to 2021.

Exhibit 7

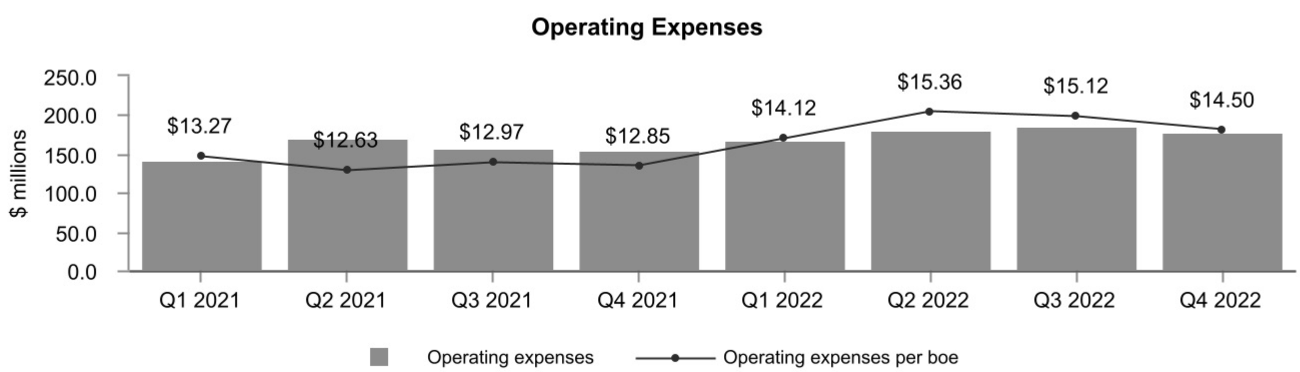


Operating Expenses

($ millions, except per boe amounts)	**2022**	2021	% Change
Operating expenses	**713.1**	625.3	14
Per boe	**14.77**	12.91	14

Operating expenses increased 14 percent in 2022 compared to 2021. The increases were primarily attributable to cost inflation throughout multiple cost categories, including gathering and processing, utilities, fuel, labour and trucking. Field activity levels, including well servicing and repair and maintenance, increased in 2022 to maximize production in response to stronger commodity prices. On a per boe basis, operating costs increased 14 percent in 2022 compared to 2021.

Exhibit 8

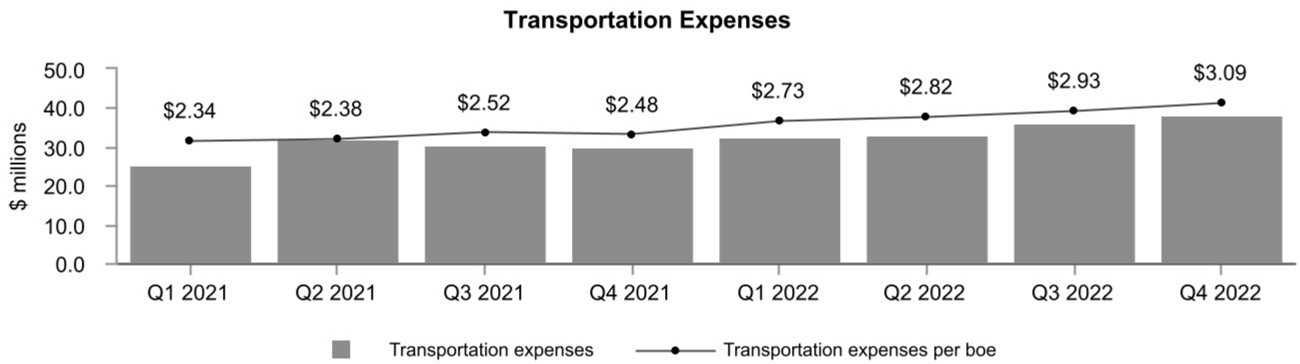


Transportation Expenses

($ millions, except per boe amounts)	**2022**	2021	% Change
Transportation expenses	**139.8**	117.7	19
Per boe	**2.90**	2.43	19

Transportation expenses increased 19 percent in 2022 compared to 2021, primarily due to higher pipeline tariffs and an increase in trucking costs and activity. On a per boe basis, transportation expenses increased by $0.47 per boe in 2022 compared to 2021.

Exhibit 9



Netback

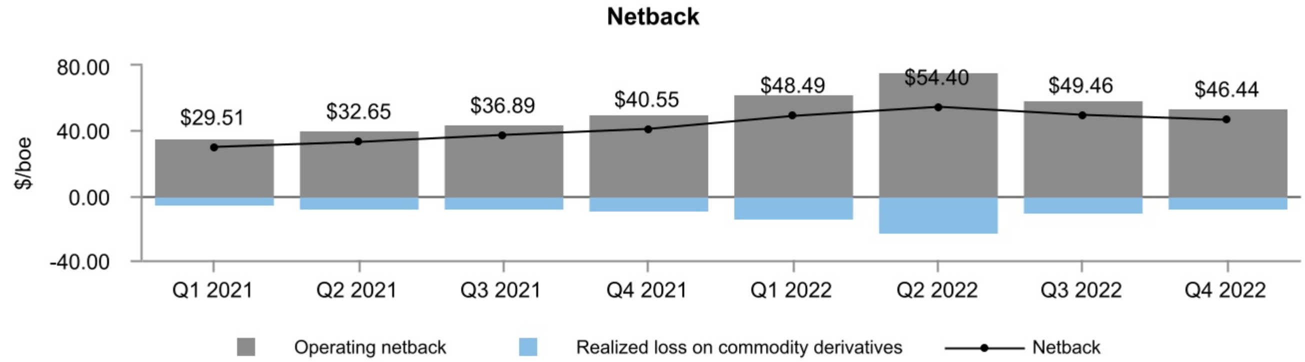
	2022	2021	
	Total [(2)] **($/boe)**	Total [(2)] ($/boe)	% Change
Oil and gas sales	**93.06**	66.21	41
Royalties	**(12.45)**	(8.44)	48
Operating expenses	**(14.77)**	(12.91)	14
Transportation expenses	**(2.90)**	(2.43)	19
Operating netback [(1)]	**62.94**	42.43	48
Realized loss on commodity derivatives	**(13.29)**	(7.45)	78
Netback [(1)]	**49.65**	34.98	42

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

(2) The dominant production category for the Company's properties is crude oil and condensate. These categories include associated natural gas and NGL volumes, therefore, the total operating netback and netback have been presented.

The Company's operating netback for the year ended December 31, 2022 increased significantly to $62.94 per boe from $42.43 per boe in 2021. The increase in the Company's operating netback was primarily due to the increase in average selling price, partially offset by higher royalties and the increases in operating and transportation expenses. The increase in the Company's netback was a result of the increase in the operating netback, partially offset by an increased realized loss on commodity derivatives.

Exhibit 10


Netback
80.00
40.00
0.00
-40.00
$/boe
$29.51
$32.65
$36.89
$40.55
$48.49
$54.40
$49.46
$46.44
Q1 2021
Q2 2021
Q3 2021
Q4 2021
Q1 2022
Q2 2022
Q3 2022
Q4 2022
Operating netback
Realized loss on commodity derivatives
Netback

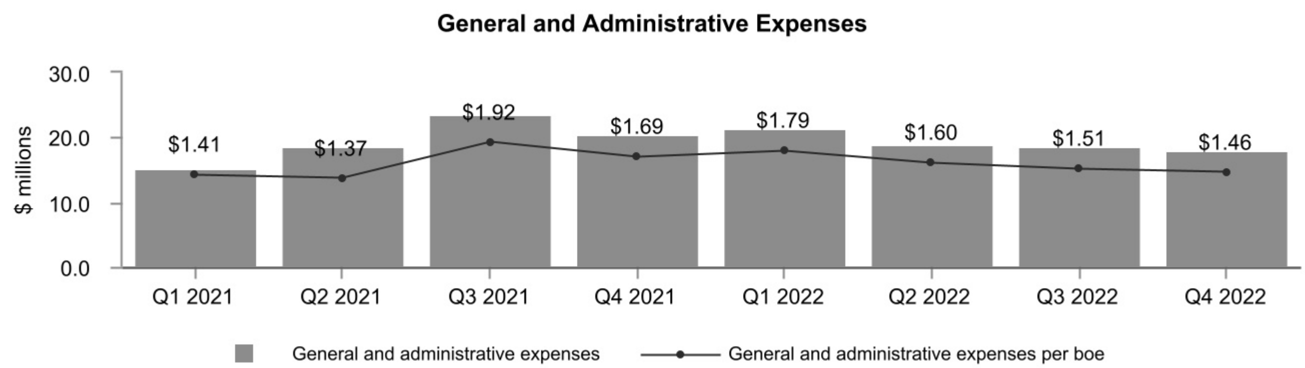
General and Administrative Expenses

($ millions, except per boe amounts)	**2022**	2021	% Change
Gross general and administrative expenses	**137.3**	140.0	(2)
Overhead recoveries	**(20.5)**	(19.4)	6
Capitalized	**(35.0)**	(30.8)	14
Total general and administrative expenses	**81.8**	89.8	(9)
Transaction costs	**(5.1)**	(12.5)	(59)
General and administrative expenses	**76.7**	77.3	(1)
Per boe	**1.59**	1.60	(1)

General and administrative ("G&A") expenses and G&A expenses per boe remained relatively consistent year over year. The impact of higher employee costs with return to office and higher professional fees were offset by lower transaction costs in 2022.

Transaction costs relate to the Company's acquisition and disposition transactions. Refer to *Capital Acquisitions and Dispositions* section in this MD&A for further information.

Exhibit 11



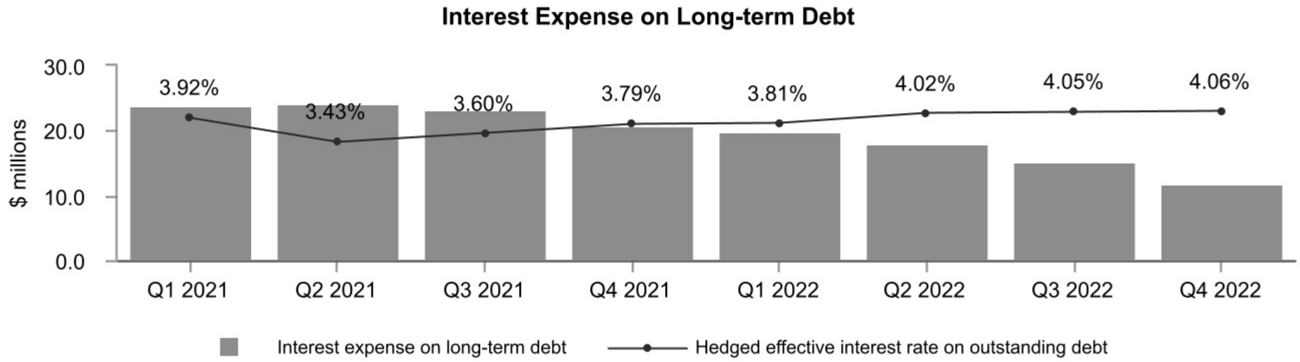
Interest Expense

($ millions, except per boe amounts)	**2022**	2021	% Change
Interest expense on long-term debt	**64.7**	88.9	(27)
Unrealized (gain) loss on interest derivative contracts	**(1.1)**	1.7	(165)
Interest expense	**63.6**	90.6	(30)
Per boe	**1.32**	1.87	(29)

Interest expense on long-term debt decreased 27 percent in 2022, primarily due to the Company's lower average debt balances.

At December 31, 2022, all of the Company's outstanding long-term debt had fixed interest rates.

Exhibit 12


Interest Expense on Long-term Debt
$ millions
30.0
20.0
10.0
0.0
3.92%
3.43%
3.60%
3.79%
3.81%
4.02%
4.05%
4.06%
Q1 2021
Q2 2021
Q3 2021
Q4 2021
Q1 2022
Q2 2022
Q3 2022
Q4 2022
Interest expense on long-term debt
Hedged effective interest rate on outstanding debt

Foreign Exchange Gain (Loss)

($ millions)	**2022**	2021	% Change
Realized gain on CCS - principal	**63.8**	—	100
Translation of US dollar long-term debt	**(94.3)**	37.0	(355)
Unrealized gain (loss) on CCS - principal and foreign exchange swaps	**4.4**	(34.4)	(113)
Other	**7.3**	1.8	306
Foreign exchange gain (loss)	**(18.8)**	4.4	(527)

The Company hedges its foreign exchange exposure using a combination of cross currency swaps ("CCS") and foreign exchange swaps. During the year ended December 31, 2022, the Company realized a $63.8 million gain on CCS related to senior guaranteed note maturities and LIBOR loan maturities.

The Company records foreign exchange gains or losses on the period end translation of US dollar long-term debt and related accrued interest. For the year ended December 31, 2022, the Company recorded foreign exchange losses of $94.3 million, which was attributed to the weaker Canadian dollar at December 31, 2022 as compared to December 31, 2021.

For the year ended December 31, 2022, Crescent Point recorded an unrealized gain on foreign exchange derivatives of $4.4 million, due to the impact of the weaker forward Canadian dollar on the Company's CCS at December 31, 2022 as compared to December 31, 2021.

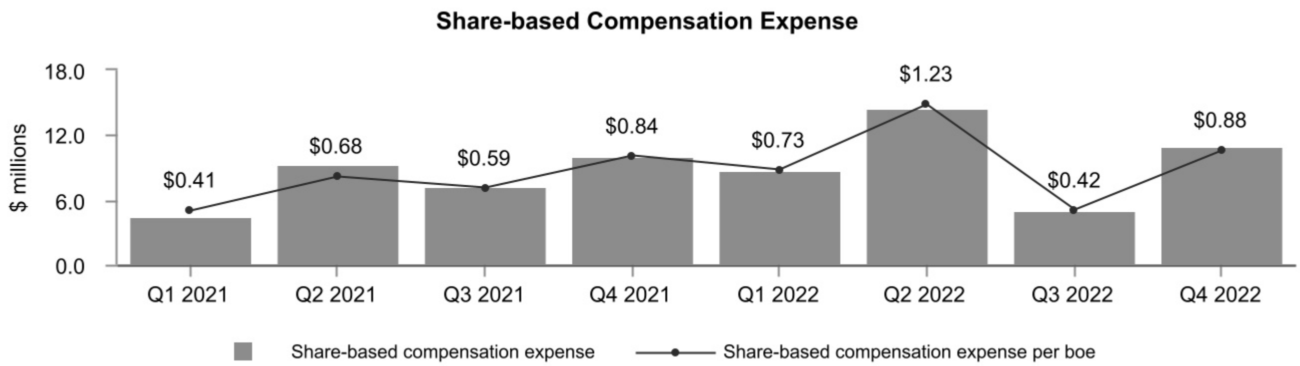
Share-based Compensation Expense

($ millions, except per boe amounts)	**2022**	2021	% Change
Share-based compensation costs	**77.3**	77.7	(1)
Realized gain on equity derivative contracts	**(26.4)**	(9.7)	172
Unrealized (gain) loss on equity derivative contracts	**2.9**	(22.8)	(113)
Capitalized	**(14.7)**	(14.3)	3
Share-based compensation expense	**39.1**	30.9	27
Per boe	**0.81**	0.64	27

Share-based compensation ("SBC") costs remained consistent year over year.

In 2022, the Company recognized a realized gain on equity derivative contracts of $26.4 million, which was primarily due to the maturity of in-the-money equity derivative contracts in the first quarter of 2022. The Company also recognized an unrealized loss on equity derivative contracts of $2.9 million compared to an unrealized gain of $22.8 million in 2021. The unrealized loss in 2022 was primarily due to the maturity of in-the-money equity derivative contracts in the first quarter of 2022, partially offset by the increase in the Company's share price at December 31, 2022 compared to December 31, 2021.

Exhibit 13



Share-based Compensation Expense
$ millions
18.0
12.0
6.0
0.0
$0.41
$0.68
$0.59
$0.84
$0.73
$1.23
$0.42
$0.88
Q1 2021
Q2 2021
Q3 2021
Q4 2021
Q1 2022
Q2 2022
Q3 2022
Q4 2022
Share-based compensation expense
Share-based compensation expense per boe

The following table summarizes the number of restricted shares, Employee Share Value Plan ("ESVP") awards, Performance Share Units ("PSUs"), Deferred Share Units ("DSUs") and stock options outstanding:

	December 31, 2022	December 31, 2021
Restricted Share Bonus Plan (1)	**2,244,738**	3,267,717
Employee Share Value Plan	**5,274,478**	8,329,291
Performance Share Unit Plan (2)	**2,713,176**	3,214,620
Deferred Share Unit Plan	**1,745,879**	1,556,780
Stock Option Plan (3)	**3,889,130**	5,839,464

(1) At December 31, 2022, the Company was authorized to issue up to 11,210,550 common shares (December 31, 2021 - 12,924,280 common shares).

(2) Based on underlying units before any effect of performance multipliers.

(3) At December 31, 2022, the weighted average exercise price is $4.43 per share (December 31, 2021 - $4.04 per share).

As of the date of this report, the Company had 2,241,843 restricted shares, 5,243,262 ESVP awards, 3,550,132 PSUs, 1,754,286 DSUs and 3,862,168 stock options outstanding.

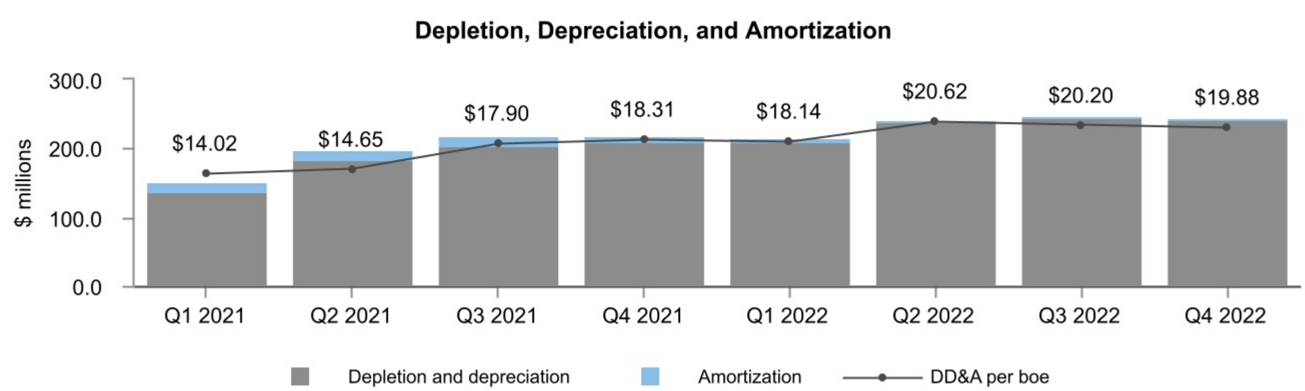
Depletion, Depreciation and Amortization

($ millions, except per boe amounts)	**2022**	2021	% Change
Depletion and depreciation	**936.5**	735.1	27
Amortization of exploration and evaluation undeveloped land	**15.2**	51.0	(70)
Depletion, depreciation and amortization	**951.7**	786.1	21
Per boe	**19.71**	16.23	21

For the year ended December 31, 2022, the Company's depletion, depreciation and amortization ("DD&A") rate increased to $19.71 per boe compared to $16.23 per boe in 2021. The increase in the DD&A rate per boe in 2022 was primarily attributable to the impairment reversal recorded in the first quarter of 2022, which increased the carrying value of the Company's property, plant and equipment ("PP&E"), partially offset by the Saskatchewan Viking disposition in July 2022.

DD&A increased 21 percent compared to 2021, primarily due to higher DD&A rates, partially offset by lower amortization of exploration and evaluation ("E&E") undeveloped land.

Exhibit 14



Impairment Reversal

($ millions, except per boe amounts)	**2022**	2021	% Change
Impairment reversal	**(428.6)**	(2,514.4)	(83)
Per boe	**(8.88)**	(51.92)	(83)

The Company recognized a net impairment reversal of $428.6 million during 2022 compared to an impairment reversal of $2.51 billion during 2021. In the first quarter of 2022, the Company recognized an impairment reversal of $1.54 billion on its development and production assets primarily due to higher forecast benchmark commodity prices at March 31, 2022 compared to June 30, 2021, which was the last time the Company conducted an impairment test. In the first quarter impairment test the Company also increased its forecast costs based on the environment and expectations at that time.

In the fourth quarter of 2022, the Company recognized an impairment loss of $985.0 million on its Southeast Saskatchewan and Southwest Saskatchewan development and production assets primarily due to the persistent inflationary environment which resulted in further increases to forecast costs as compared to March 31, 2022. In addition, a change in the expected development timing of these assets contributed to the impairment loss.

At December 31, 2022, the Company classified certain non-core assets in Alberta as held for sale. Immediately prior to classifying the assets held for sale, the Company conducted a review of the assets' recoverable amounts and recorded an impairment loss of $71.3 million on PP&E. The Company also recorded an impairment loss of $56.0 million during the first quarter of 2022 related to assets held for sale at March 31, 2022. These impairments were recorded as a component of the net impairment reversal in 2022. See Note 8 – "Property, Plant and Equipment" in the audited consolidated financial statements for the year ended December 31, 2022 for further information.

Other Income

The Company recorded other income of $58.8 million in 2022 compared to $99.4 million in 2021. Other income was comprised primarily of gains on asset dispositions and government grants for decommissioning expenditures in both 2022 and 2021. See Note 19 – "Other Income" in the audited consolidated financial statements for the year ended December 31, 2022 for further information.

Taxes

($ millions)	**2022**	2021	% Change
Current tax expense	**—**	—	—
Deferred tax expense	**387.9**	799.7	(51)

Current Tax Expense

In both the years ended December 31, 2022 and December 31, 2021, the Company recorded current tax expense of nil. Refer to the Company's Annual Information Form for the year ended December 31, 2022 for information on the Company's expected tax horizon.

Deferred Tax Expense

In the year ended December 31, 2022, the Company recorded deferred tax expense of $387.9 million compared to $799.7 million in 2021. The deferred tax expense for 2022 and 2021 primarily relates to the pre-tax income in each year, partially offset by a change in estimate for future usable tax pools.

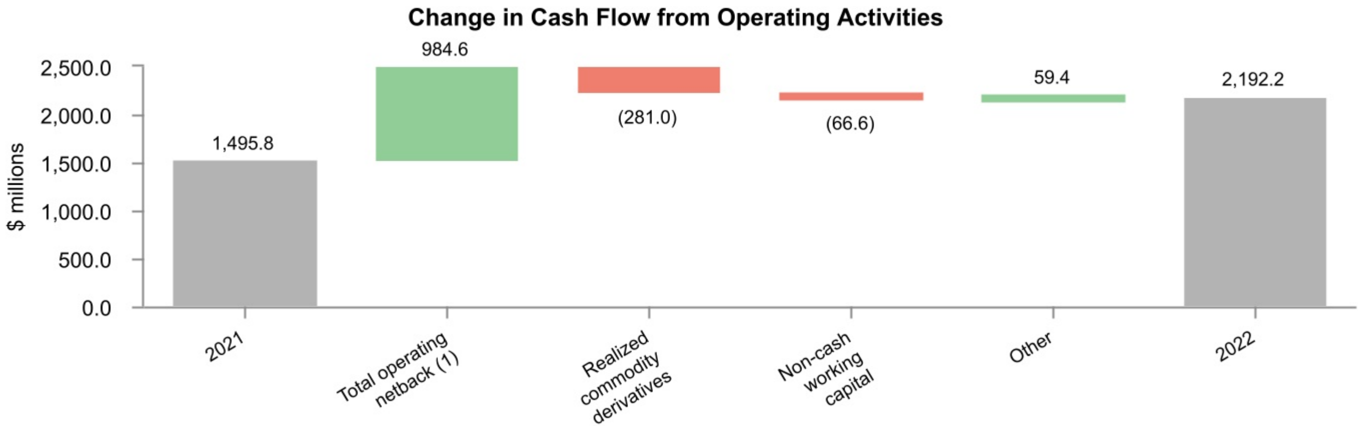
Cash Flow from Operating Activities, Adjusted Funds Flow from Operations, Net Income and Adjusted Net Earnings from Operations

($ millions, except per share amounts)	**2022**	2021	% Change
Cash flow from operating activities	**2,192.2**	1,495.8	47
Adjusted funds flow from operations (1)	**2,232.4**	1,476.9	51
Net income	**1,483.4**	2,364.1	(37)
Net income per share - diluted	**2.60**	4.11	(37)
Adjusted net earnings from operations (1)	**965.7**	515.3	87
Adjusted net earnings from operations per share - diluted (1)	**1.69**	0.90	88

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Cash flow from operating activities increased from $1.50 billion in 2021 to $2.19 billion in 2022.

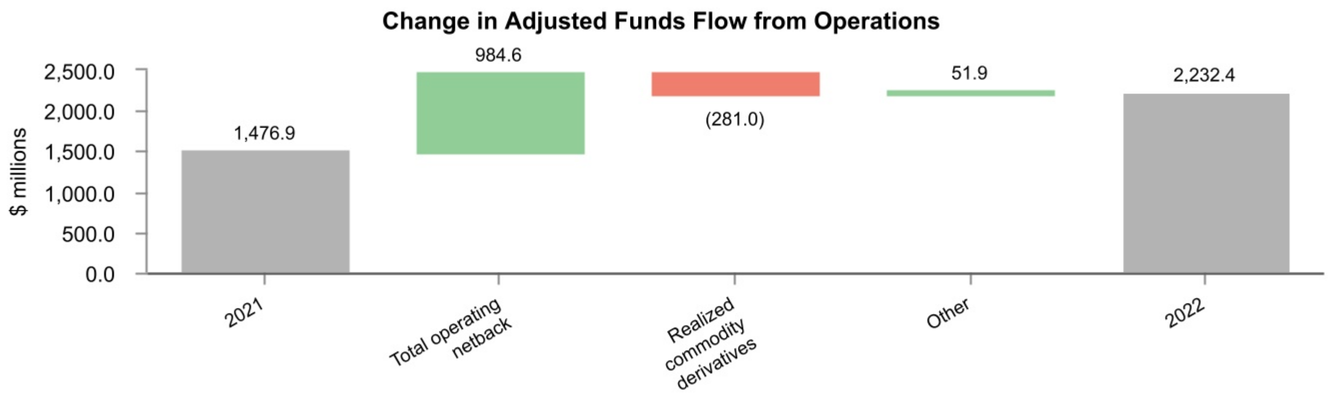
Exhibit 15



(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

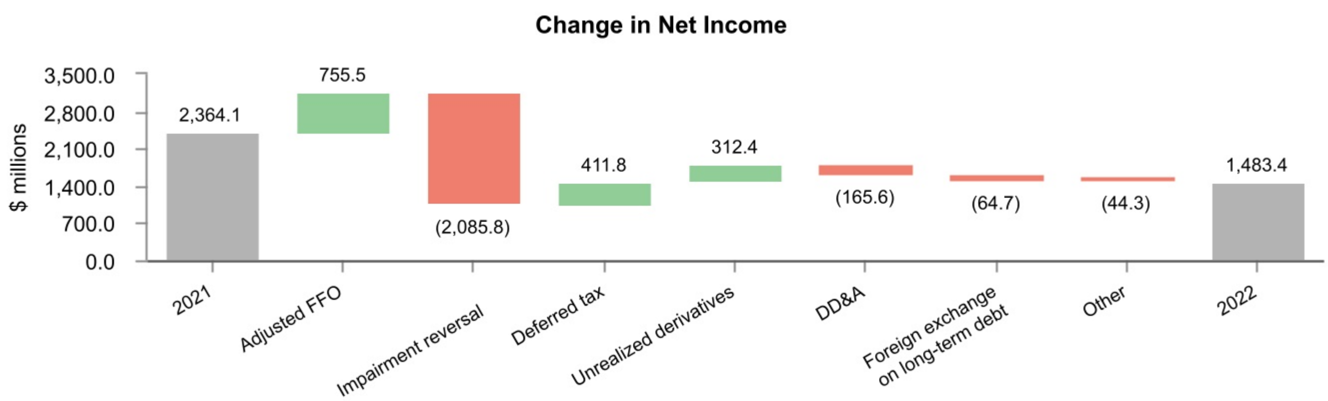
The Company's adjusted FFO increased from $1.48 billion in 2021 to $2.23 billion in 2022.

Exhibit 16



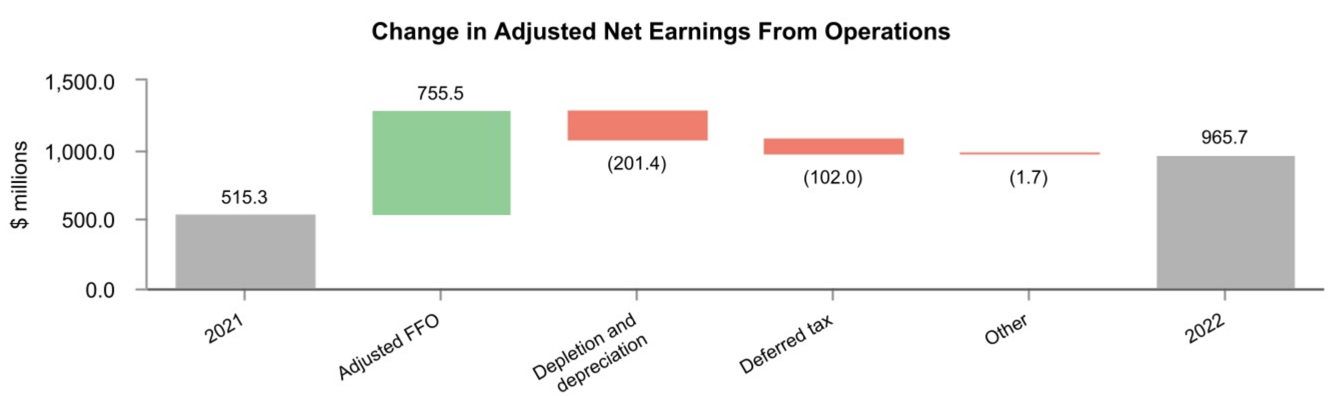
The Company reported net income of $1.48 billion in 2022 ($2.60 per fully diluted share) compared to $2.36 billion in 2021 ($4.11 per fully diluted share).

Exhibit 17



The Company's adjusted net earnings from operations was $965.7 million in 2022 ($1.69 per fully diluted share) compared to $515.3 million in 2021 ($0.90 per fully diluted share).

Exhibit 18



Excess Cash Flow and Discretionary Excess Cash Flow

Excess cash flow increased from $788.4 million in 2021 to $1.15 billion in 2022, primarily as a result of the increases in adjusted FFO, partially offset by higher capital expenditures. Discretionary excess cash flow increased from $766.7 million to $1.00 billion in 2022, as a result of the increase in excess cash flow, partially offset by the increase in base dividends.

Excess cash flow and discretionary excess cash flow are specified financial measures that do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Dividends Declared

($ millions, except per share amounts)	2022	2021	% Change
Dividends declared	**200.6**	47.8	320
Dividends declared per share	**0.3600**	0.0825	336

In October 2022, Crescent Point declared a quarterly cash dividend of $0.0800 per share to be paid on January 3, 2023. In December 2022, Crescent Point declared a quarterly cash dividend of $0.1000 per share to be paid on April 3, 2023. Both quarterly dividends were accrued at December 31, 2022. In November 2022, the Company paid a special cash dividend of $0.0350 per share.

In 2022, the Company declared total cash dividends of $0.3600 per share, compared to $0.0825 per share in 2021.

Related Party Transactions

Key management personnel of the Company include its directors and executive officers. In 2022, the Company recorded $6.1 million (2021 – $6.1 million) relating to compensation of key management personnel and nil (2021 – $2.8 million) for severance relating to key management personnel. In 2022, share-based compensation costs relating to compensation of key management personnel was $24.2 million (2021 – $23.4 million) and nil (2021 – $1.8 million) for share-based compensation severance relating to key management personnel.

Capital Expenditures

($ millions)	2022	2021	% Change
Capital acquisitions	**90.7**	942.4	(90)
Capital dispositions	**(283.6)**	(99.0)	186
Development capital expenditures	**956.1**	624.2	53
Land expenditures	**19.2**	4.9	292
Capitalized administration [(1)]	**49.5**	44.5	11
Corporate assets	**2.6**	2.5	4
Total	**834.5**	1,519.5	(45)

(1) Capitalized administration excludes capitalized equity-settled SBC.

Capital Acquisitions and Dispositions

Major Property Acquisitions and Dispositions

Saskatchewan Viking Disposition

On July 6, 2022, the Company disposed of its non-core Saskatchewan Viking assets for consideration of $241.7 million. These assets had a net carrying value of $219.7 million, resulting in a gain of $22.6 million.

Kaybob Duvernay Acquisition

On August 31, 2022, the Company acquired certain Kaybob Duvernay assets for total consideration of $87.0 million ($61.8 million was allocated to PP&E and $28.0 million was allocated to E&E assets, including $2.8 million related to decommissioning liability).

Minor Property Acquisitions and Dispositions

In the year ended December 31, 2022, the Company completed minor property acquisitions and dispositions for net consideration received of $38.2 million. These assets had a net carrying value of $34.9 million, resulting in a gain of $3.3 million.

Assets Held for Sale

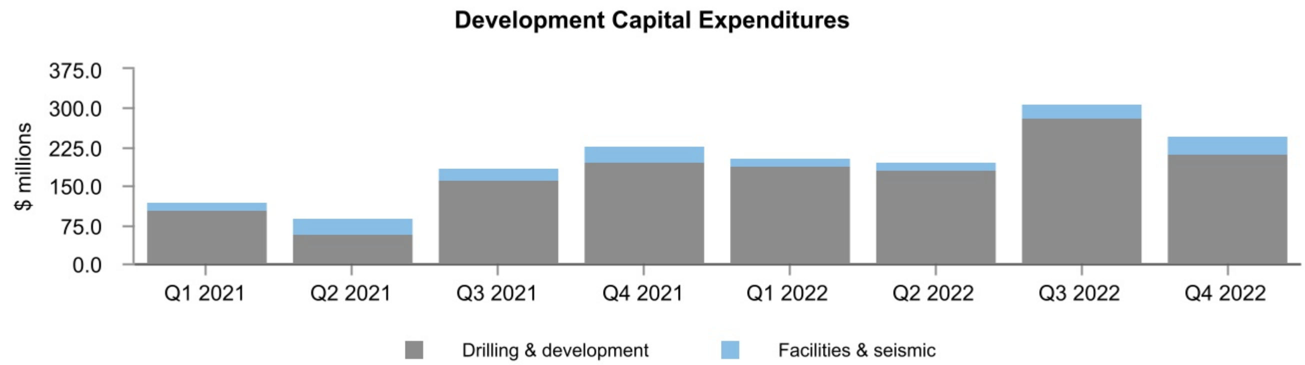
At December 31, 2022, the Company classified certain non-core assets in Alberta as held for sale. These assets were recorded at the lesser of their carrying value and recoverable amount.

Development Capital Expenditures

The Company's development capital expenditures for the year ended December 31, 2022 were $956.1 million, compared to $624.2 million in 2021. Spending in 2022 was focused on the Company's core assets with $279.2 million of spending in Alberta, $258.2 million in Northern U.S., $237.0 million in Southeast Saskatchewan and $181.7 million in Southwest Saskatchewan. The high inflationary environment resulted in higher unit costs in 2022 and contributed to the increase in spending levels over 2021. During 2022, 219 (206.6 net) wells were drilled and $90.4 million was spent on facilities and seismic.

Refer to the *Guidance* section in this MD&A for Crescent Point's development capital expenditure guidance for 2023.

Exhibit 19



Goodwill

The Company's goodwill balance is attributable to corporate acquisitions completed during the period from 2003 through 2012. The goodwill balance as at December 31, 2022 was $203.9 million compared to $211.5 million at December 31, 2021. The decrease of $7.6 million is attributable to the disposition of the non-core Saskatchewan Viking assets and other minor asset dispositions.

Other Current Liabilities

At December 31, 2022, other current liabilities consist of $49.1 million related to the current portion of long-term share-based compensation, $24.9 million related to the current portion of lease liabilities, and $41.6 million related to decommissioning liability.

Other Long-Term Liabilities

At December 31, 2022, other long-term liabilities consist of $40.8 million of long-term compensation liability related to share-based compensation.

Lease Liability

At December 31, 2022, the Company had $124.1 million of lease liabilities for contracts related to office space, fleet vehicles and equipment.

Decommissioning Liability

The decommissioning liability, including liabilities associated with assets held for sale, decreased by $214.9 million during 2022, from $918.8 million at December 31, 2021 to $703.9 million at December 31, 2022. The decrease primarily relates to an increase in discount rate resulting from higher market interest rates, liabilities disposed through capital dispositions and liabilities settled through the Company's abandonment and reclamation program. The liability is based on estimated undiscounted cash flows before inflation to settle the obligation of $931.8 million.

Liquidity and Capital Resources

Capitalization Table ($ millions, except share, per share, ratio and percent amounts)	**December 31, 2022**	December 31, 2021
Net debt [1]	**1,154.7**	2,005.0
Shares outstanding	**550,888,983**	579,484,032
Market price at end of period (per share)	**9.66**	6.75
Market capitalization	**5,321.6**	3,911.5
Enterprise value [1]	**6,476.3**	5,916.5
Net debt as a percentage of enterprise value [1]	**18**	34
Adjusted funds flow from operations [1] [2]	**2,232.4**	1,476.9
Net debt to adjusted funds flow from operations [1] [3]	**0.5**	1.4

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

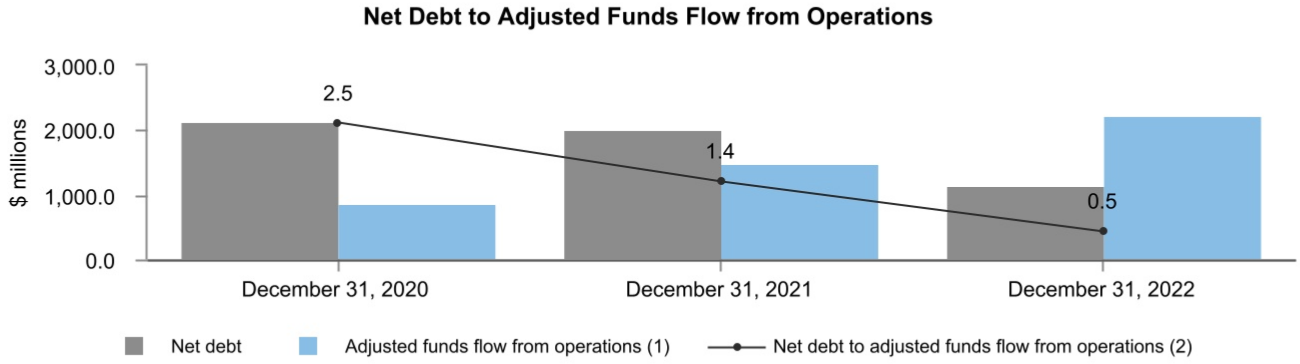
(2) The sum of adjusted funds flow from operations for the trailing four quarters.

(3) The net debt reflects the financing of acquisitions, however, the adjusted funds flow from operations only reflects adjusted funds flow from operations generated from the acquired properties since the closing date of the acquisitions.

At December 31, 2022, Crescent Point's enterprise value was $6.48 billion and the Company was capitalized with 82 percent equity compared to $5.92 billion and 66 percent at December 31, 2021, respectively. The Company's net debt to adjusted funds flow from operations ratio at December 31, 2022 decreased to 0.5 times from 1.4 times at December 31, 2021. The decrease was largely due to a reduction in net debt as a result of excess cash flow generated in 2022, and higher adjusted funds flow from operations, primarily as a result of the increase in the Cdn$ WTI benchmark price.

Crescent Point's market capitalization increased to $5.32 billion at December 31, 2022, from $3.91 billion at December 31, 2021, primarily due to the increase in the Company's share price.

Exhibit 20



(1) The sum of adjusted funds flow from operations for the trailing four quarters.

(2) The net debt reflects the financing of acquisitions, however, the adjusted funds flow from operations only reflects adjusted funds flow from operations generated from the acquired properties since the closing date of the acquisitions.

The Company has combined revolving credit facilities of $2.36 billion, including a $2.26 billion syndicated unsecured credit facility with eleven banks and a $100.0 million unsecured operating credit facility with one Canadian chartered bank. The current maturity date of the facilities is November 26, 2026. As at December 31, 2022, the Company was undrawn on its bank credit facilities and had $1.8 million outstanding pursuant to letters of credit.

At December 31, 2022, the Company has senior guaranteed notes of US$921.0 million and Cdn$195.0 million outstanding. The notes are unsecured and rank *pari passu* with the Company's bank credit facilities and carry a bullet repayment on maturity. Crescent Point entered into various CCS to hedge its foreign exchange exposure on its US dollar long-term debt. During the year ended December 31, 2022, the Company repaid senior guaranteed note maturities of US$200.0 million and Cdn$25.0 million.

The Company is in compliance with all debt covenants at December 31, 2022 which are listed in the table below:

Covenant Description	Maximum Ratio	**December 31, 2022**
Senior debt to adjusted EBITDA (1) (2)	3.5	**0.62**
Total debt to adjusted EBITDA (1) (3)	4.0	**0.62**
Senior debt to capital (2) (4)	0.55	**0.19**

(1) Adjusted EBITDA is calculated as earnings before interest, taxes, depletion, depreciation, amortization, impairment and impairment reversals, adjusted for certain non-cash items. Adjusted EBITDA is calculated on a trailing twelve month basis adjusted for material acquisitions and dispositions.

(2) Senior debt is calculated as the sum of amounts drawn on the combined facilities, outstanding letters of credit and the principal amount of the senior guaranteed notes.

(3) Total debt is calculated as the sum of senior debt plus subordinated debt. Crescent Point does not have any subordinated debt.

(4) Capital is calculated as the sum of senior debt and shareholders' equity and excludes the effect of unrealized derivative gains or losses and the adoption of IFRS 16.

The Company's ongoing working capital requirements are expected to be financed through cash, adjusted funds flow from operations and its bank credit facilities.

Shareholders' Equity

At December 31, 2022, Crescent Point had 550.9 million common shares issued and outstanding compared to 579.5 million common shares at December 31, 2021. The decrease of 28.6 million shares is due to shares purchased for cancellation under the Normal Course Issuer Bid ("NCIB"), partially offset by shares issued pursuant to the Restricted Share Bonus Plan and stock options exercised pursuant to the Stock Option Plan.

As of the date of this report, the Company had 547,957,237 common shares outstanding.

Normal Course Issuer Bid

On March 4, 2022, the Company announced the acceptance by the Toronto Stock Exchange of its notice to implement an NCIB. The NCIB allows the Company to purchase, for cancellation, up to 57,309,975 common shares, or 10 percent of the Company's public float, as at February 28, 2022. The NCIB commenced on March 9, 2022 and is due to expire on March 8, 2023.

In 2022, the Company purchased 31.3 million common shares for a total consideration of $294.2 million. The total cost paid, including commissions and fees, was recognized directly as a reduction in shareholders' equity. Under the NCIB, all common shares purchased are cancelled.

Contractual Obligations and Commitments

At December 31, 2022, the Company had contractual obligations and commitments as follows:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Off balance sheet commitments					
Operating [(1)]	11.7	15.7	9.8	11.9	49.1
Gas processing [(2)]	64.6	105.4	88.5	291.8	550.3
Transportation	43.3	74.8	41.5	40.1	199.7
Capital	7.3	—	—	—	7.3
Total contractual commitments [(3)]	126.9	195.9	139.8	343.8	806.4

(1) Includes operating costs on the Company's office space, net of $18.1 million of recoveries from subleases.

(2) Gas handling agreement with a gas processor that includes a long-term volume commitment. The agreement is only terminable in very limited circumstances and if the termination were to occur because of the Company's default, the Company would be obligated to pay its processing commitment. If the processor were to terminate the agreement, the Company would need to seek alternative processing arrangements.

(3) Excludes contracts accounted for under IFRS 16. See Note 12 - "Leases" in the annual consolidated financial statements for the year ended December 31, 2022 for further information.

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Other contractual commitments					
Senior guaranteed notes [(1)]	486.6	816.2	26.9	—	1,329.7
Total contractual commitments	486.6	816.2	26.9	—	1,329.7

(1) These amounts include the notional principal and interest payments pursuant to the related CCS which fix the amounts due in Canadian dollars.

Subsequent Events

Acquisition of Kaybob Duvernay Assets

On January 11, 2023, Crescent Point completed the acquisition of certain Kaybob Duvernay assets in Alberta for cash consideration of $370.6 million, including closing adjustments, which is expected to be allocated substantially to PP&E and E&E. Cash consideration was funded primarily through cash on hand and included a deposit on acquisition of $18.7 million.

Off Balance Sheet Arrangements

The Company has off-balance sheet arrangements consisting of various contracts which are entered into in the normal course of operations. Contracts that contain a lease are accounted for under IFRS 16 and recorded on the balance sheet as at December 31, 2022. All other contracts which are entered into in the normal course of operations are captured in the "off balance sheet commitments" table in the *Contractual Obligations and Commitments* section above and no asset or liability value has been assigned to these leases on the balance sheet as at December 31, 2022.

Critical Accounting Estimates

The preparation of the Company's consolidated financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. A summary of the significant accounting policies used by Crescent Point can be found in Note 3 – "Significant Accounting Policies" in the audited consolidated financial statements for the year ended December 31, 2022. The following discussion outlines what management believes are the most critical policies involving the use of estimates and assumptions.

Oil and gas activities

Reserves estimates, although not reported as part of the Company's consolidated financial statements, can have a significant effect on net income, assets and liabilities as a result of their impact on DD&A, decommissioning liability, deferred taxes, asset impairments and impairment reversals, and business combinations. Independent petroleum reservoir engineers perform evaluations of the Company's oil and gas reserves on an annual or as needed basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

For purposes of impairment testing, PP&E is aggregated into cash-generating units ("CGUs"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations.

The determination of technical feasibility and commercial viability is subject to judgment as it is based on the presence of reserves and results in the transfer of assets from E&E to PP&E.

Decommissioning liability

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are based on estimates with respect to the cost and timing of decommissioning.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Fair value measurement

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by its very nature, is subject to measurement uncertainty. Estimates included in the determination of the fair value of derivative instruments include forward benchmark prices, discount rates, share price and forward foreign exchange rates.

Joint control

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the capital and operating activities of the projects it undertakes with partners and when the decisions in relation to those activities require unanimous consent.

Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax assets and liabilities recognize the extent that temporary differences will be receivable and payable in future periods. The calculation of the asset and liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, expected cash flows from estimated proved plus probable reserves and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

Risk Factors

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have an impact on Crescent Point's business. Financial risks the Company is exposed to include: marketing production at an acceptable price given market conditions and market access; finding and producing reserves at a reasonable cost; volatility in market prices for oil and natural gas; volatility in crude oil price differentials; fluctuations in foreign exchange and interest rates; stock market volatility; debt service which may limit timing or amount of dividends as well as market price of shares; the continued availability of adequate debt and equity financing and cash flow to fund planned expenditures; sufficient liquidity for future operations; lost revenue or increased expenditures as a result of delayed or denied environmental, safety or regulatory approvals; adverse changes to income tax laws or other laws or government incentive programs and regulations relating to the oil and gas industry; cost of capital risk to carry out the Company's operations; and uncertainties associated with credit facilities and counterparty credit risk.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on the Company's ability to achieve objectives. Operational risks to which Crescent Point is exposed include: uncertainties associated with estimating oil and natural gas reserves; incorrect assessments of the value of acquisitions and exploration and development programs; failure to realize the anticipated benefits of acquisitions and dispositions; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; inability to secure adequate product transportation including sufficient crude-by-rail or other alternate transportation; delays in business operations, pipeline restrictions, public infrastructure constraints including blockades, blowouts; unforeseen title defects; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; outbreaks; mobility restrictions, loss and health of key personnel; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; competitive action by other companies; the ability of suppliers to meet commitments and risks; and cyber security risks.

COVID-19 Pandemic

The onset of the COVID-19 pandemic, and actions taken in response, resulted in a significant contraction in the global economy and in the oil and gas industry. The demand for and pricing of energy products has since returned to historical levels.

Although the worst impacts of the COVID-19 pandemic on the Company's financial condition and operations appear to have passed, future developments may have an adverse effect on the Company's financial condition, income, results from operations and cash flows. Other risks disclosed in the Company's Annual Information Form, for the year ended December 31, 2022, and in this MD&A may be heightened and there may also be effects that are not currently known.

Safety, Environmental and Regulatory Risks

Safety, environmental and regulatory risks are the risks of loss or lost opportunity resulting from changes to laws governing safety, the environment, royalties and taxation. Safety, environmental and regulatory risks Crescent Point is exposed to include: indigenous land claims; uncertainties associated with regulatory approvals; uncertainty of government policy changes; the risk of carrying out operations with minimal environmental impact; changes in or adoption of new laws and regulations or changes in how they are interpreted or enforced; obtaining required approvals of regulatory authorities and stakeholder support for activities and growth plans.

The Company's operations are subject to costs being incurred to pay carbon taxes, to reduce GHG emissions (including methane emissions) and to perform necessary monitoring, measurement, verification and reporting of GHG emissions. Future environmental legislation may require further reductions in emissions from the Company's operations and result in increased capital and operational expenditures related to the transition to a low-carbon economy.

Refer to the Company's Annual Information Form for the year ended December 31, 2022 for additional information on the Company's risk factors.

Risk Management

Crescent Point is committed to identifying and managing its risks in the near term, as well as on a strategic and longer term basis at all levels in the organization in accordance with the Company's Board-approved Risk Management and Counterparty Credit Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. Crescent Point takes a proactive approach to the identification and management of issues that can affect the Company’s assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management.

Specific actions Crescent Point takes to ensure effective risk management include but are not limited to: employing qualified professional and technical staff; concentrating in a limited number of areas with lower risk development projects; utilizing market proven technology for finding and developing reserves; constructing quality, environmentally sensitive and safe production facilities; adopting and communicating sound policies governing all areas of our business; maximizing operational control of drilling and production operations; strategic hedging program including commodity prices, interest and foreign exchange rates; adhering to conservative borrowing guidelines and maintaining significant liquidity; monitoring counterparty creditworthiness and obtaining supplementary credit protection when warranted.

Changes in Accounting Policies

New accounting standards and amendments not yet adopted

Income Taxes

IAS 12 *Income Taxes* was amended in May 2021 by the IASB which requires companies, on initial recognition, to recognize deferred tax on transactions that result in equal amounts of taxable and deductible temporary differences. The amendment is effective for fiscal years beginning on or after January 1, 2023.

Presentation of Financial Statements

IAS 1 *Presentation of Financial Statements* was amended in January 2020 by the IASB to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. This amendment is effective for fiscal years beginning on or after January 1, 2024.

Selected Annual Information

($ millions, except per share amounts)	2022	2021	2020
Oil and gas sales	**4,493.1**	3,206.5	1,692.2
Average daily production			
Crude oil and condensate (bbls/d)	**91,679**	95,839	95,859
NGLs (bbls/d)	**17,039**	17,769	14,542
Natural gas (mcf/d)	**141,384**	114,452	67,447
Total (boe/d)	**132,282**	132,683	121,642
Net income (loss) (1)	**1,483.4**	2,364.1	(2,519.9)
Net income (loss) per share (1)	**2.62**	4.15	(4.76)
Net income (loss) per share - diluted (1)	**2.60**	4.11	(4.76)
Adjusted net earnings from operations (2)	**965.7**	515.3	177.4
Adjusted net earnings from operations per share (2)	**1.70**	0.91	0.34
Adjusted net earnings from operations per share – diluted (2)	**1.69**	0.90	0.33
Cash flow from operating activities	**2,192.2**	1,495.8	860.5
Adjusted funds flow from operations (2)	**2,232.4**	1,476.9	874.4
Adjusted working capital surplus (deficiency) (2)	**95.1**	(201.6)	(93.4)
Total assets	**9,486.4**	9,171.2	6,645.9
Total liabilities	**2,993.0**	3,765.9	3,823.1
Net debt (2)	**1,154.7**	2,005.0	2,149.2
Weighted average shares - diluted (millions)	**571.1**	575.1	531.8
Capital acquisitions	**90.7**	942.4	1.4
Capital dispositions	**(283.6)**	(99.0)	(508.2)
Development capital expenditures	**956.1**	624.2	654.8
Dividends declared	**200.6**	47.8	9.4
Dividends declared per share	**0.3600**	0.0825	0.0175

(1) Net income (loss) and net income (loss) before discontinued operations are the same.

(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

A significant factor in Crescent Point's 2020, 2021 and 2022 financial and operational results was the COVID-19 pandemic and the resulting impact on commodity prices. In 2020, with the onset of the pandemic, the global economy collapsed sending commodity prices materially lower, which significantly impacted the Company's 2020 financial results. As the global economy recovered in 2021 and 2022, demand for goods, services and commodities increased, which drove higher commodity prices and improvements in the Company's results. Continued robust demand for goods and services supported strong commodity prices and drove persistently high inflation during 2022, which resulted in Central Banks initiating interest rate increases to cool their economies.

Fluctuating levels of acquisition and disposition activity impacted the Company's portfolio, production levels and financial results.

Net income (loss) over the past three years fluctuated primarily due to volatile commodity prices resulting in varying levels of oil and gas sales, PP&E impairment charges and reversals, unrealized derivative gains and losses on commodity contracts and the associated fluctuations in deferred tax expense (recovery).

Adjusted net earnings from operations fluctuated over the past three years primarily due to changes in adjusted funds flow from operations, depletion and share-based compensation expense along with associated fluctuations in the deferred tax expense (recovery).

Summary of Quarterly Results

	2022				2021			
($ millions, except per share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas sales	**1,016.6**	1,097.3	1,286.5	1,092.7	900.4	826.7	849.2	630.2
Average daily production								
Crude oil and condensate (bbls/d)	**90,759**	91,762	91,250	92,971	88,544	92,206	107,444	95,276
NGLs (bbls/d)	**17,770**	17,198	16,139	17,039	20,884	18,176	18,608	13,319
Natural gas (mcf/d)	**153,572**	144,356	130,724	136,667	125,871	130,823	135,531	64,732
Total (boe/d)	**134,124**	133,019	129,176	132,788	130,407	132,186	148,641	119,384
Net income (loss)	**(498.1)**	466.4	331.5	1,183.6	121.6	77.5	2,143.3	21.7
Net income (loss) per share	**(0.90)**	0.83	0.58	2.05	0.21	0.13	3.68	0.04
Net income (loss) per share – diluted	**(0.90)**	0.82	0.58	2.03	0.21	0.13	3.65	0.04
Adjusted net earnings from operations (1)	**209.8**	242.9	272.1	240.9	160.0	142.6	117.6	95.1
Adjusted net earnings from operations per share (1)	**0.38**	0.43	0.48	0.42	0.27	0.25	0.20	0.18
Adjusted net earnings from operations per share – diluted (1)	**0.38**	0.43	0.47	0.41	0.27	0.24	0.20	0.18
Cash flow from operating activities	**589.5**	647.0	529.6	426.1	492.4	414.2	285.5	303.7
Adjusted funds flow from operations (1)	**522.8**	576.5	599.1	534.0	432.5	393.9	387.8	262.7
Adjusted working capital surplus (deficiency) (1)	**95.1**	47.9	(40.9)	(91.8)	(201.6)	(108.8)	(16.1)	(55.9)
Total assets	**9,486.4**	10,437.6	10,279.4	10,412.5	9,171.2	9,231.5	9,283.4	6,610.7
Total liabilities	**2,993.0**	3,224.6	3,501.3	3,901.2	3,765.9	3,897.4	4,044.4	3,777.5
Net debt (1)	**1,154.7**	1,198.3	1,467.9	1,775.2	2,005.0	2,138.8	2,324.2	2,013.4
Weighted average shares – diluted (millions)	**559.2**	567.4	575.9	582.7	587.7	587.1	587.8	536.6
Capital acquisitions	**1.3**	88.2	0.3	0.9	5.2	0.9	936.3	—
Capital dispositions	**1.2**	(244.1)	(37.8)	(2.9)	(0.1)	(3.8)	(87.9)	(7.2)
Development capital expenditures	**246.4**	308.5	196.9	204.3	229.5	187.1	88.4	119.2
Dividends declared	**118.8**	44.9	37.1	(0.2)	26.0	19.0	1.5	1.3
Dividends declared per share	**0.2150**	0.0800	0.0650	—	0.0450	0.0325	0.0025	0.0025

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Over the past eight quarters, the Company's oil and gas sales have fluctuated due to volatility in the crude oil, condensate and natural gas benchmark prices, changes in production and fluctuations in corporate oil price differentials. The Company's production has fluctuated due to changes in its development capital spending levels, acquisitions and dispositions, voluntary shut-ins and subsequent reactivations, and natural declines.

Net income (loss) has fluctuated over the past eight quarters primarily due to changes in PP&E impairment charges and reversals, changes in adjusted funds flow from operations, unrealized derivative gains and losses, which fluctuate with changes in forward market prices and foreign exchange rates, gains and losses on capital dispositions, and fluctuations in deferred tax expense.

Adjusted net earnings from operations has fluctuated over the past eight quarters, primarily due to changes in adjusted funds flow from operations, depletion and share-based compensation expense along with associated fluctuations in deferred tax expense.

Capital expenditures have also fluctuated throughout this period due to the timing of acquisitions, dispositions and changes in the Company's development capital spending levels which vary based on a number of factors, including the prevailing commodity price environment.

Fourth Quarter 2022 Review

- Crescent Point's production averaged 134,124 boe/d in the fourth quarter of 2022, weighted 81 percent towards crude oil and liquids.
- Adjusted funds flow from operations totaled $522.8 million in the fourth quarter of 2022, a 9 percent decrease from $576.5 million in the third quarter of 2022. The decrease was primarily attributable to lower WTI pricing.
- During the fourth quarter of 2022, the Company spent $213.9 million on drilling and development activities, drilling 52 (49.4 net) wells. Crescent Point also spent $32.5 million on facilities and seismic, for total development capital expenditures of $246.4 million.
- Net debt was reduced by $43.6 million in the fourth quarter of 2022, ending at $1.15 billion or 0.5 times trailing adjusted funds flow from operations.
- Net loss of $498.1 million was impacted by a $985.0 million impairment charge primarily attributable to higher costs and a change in the development timing on the Company's Southeast and Southwest Saskatchewan CGUs.

Disclosure Controls and Procedures

Disclosure controls and procedures (“DC&P”), as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109 *Certification of Disclosure in Issuers’ Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in the Company’s annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Crescent Point evaluated the effectiveness of the design and operation of the Company’s DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Crescent Point’s DC&P were effective as at December 31, 2022.

Internal Controls over Financial Reporting

Internal control over financial reporting (“ICFR”), as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, includes those policies and procedures that:

1. pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Crescent Point;
2. are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Crescent Point are being made in accordance with authorizations of management and Directors of Crescent Point; and
3. are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company’s assets that could have a material effect on the financial statements.

Management is responsible for establishing and maintaining ICFR for Crescent Point. They have, as at the financial year ended December 31, 2022, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Crescent Point’s officers used to design the Company’s ICFR is the *Internal Control-Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”).

Under the supervision of Management, Crescent Point conducted an evaluation of the effectiveness of the Company’s ICFR as at December 31, 2022 based on the COSO Framework. Based on this evaluation, Management concluded that as of December 31, 2022, Crescent Point maintained effective ICFR.

The effectiveness of Crescent Point's ICFR as of December 31, 2022 was audited by PricewaterhouseCoopers LLP, as reflected in their report accompanying the Company's financial statements for the year ended December 31, 2022. There were no changes in Crescent

Point’s ICFR during the year ended December 31, 2022 that materially affected, or are reasonably likely to materially affect, the Company’s ICFR.

With the COVID-19 pandemic, the Company ensured that the operating effectiveness of current controls continued with the adoption of a work from home policy for employees as well as physical distancing protocols within field operations. Neither Crescent Point's DC&P nor its ICFR have been changed in a way that materially affects, or is reasonably likely to materially affect, Crescent Point's DC&P or ICFR, respectively, as a result of the measures taken in response to COVID-19.

It should be noted that while Crescent Point’s officers believe that the Company’s controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P and ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

Guidance

Crescent Point's guidance for 2023 is as follows:

Total Annual Average Production (boe/d) [(1)]	138,000 - 142,000
Capital Expenditures	
Development capital expenditures ($ millions)	$1,000 - $1,100
Capitalized administration ($ millions)	$40
Total ($ millions) [(2)]	$1,040 - $1,140
Other Information for 2023 Guidance	
Reclamation activities ($ millions) [(3)]	$40
Capital lease payments ($ millions)	$20
Annual operating expenses ($/boe)	$14.25 - $15.25
Royalties	13.75% - 14.25%

(1) Total annual average production (boe/d) is comprised of approximately 80% Oil, Condensate & NGLs and 20% Natural Gas.

(2) Land expenditures and net property acquisitions and dispositions are not included. Revised development capital expenditures spend is allocated on an approximate basis as follows: 90% drilling & development and 10% facilities & seismic.

(3) Reflects Crescent Point's portion of its expected total budget.

Return of Capital Outlook

Base Dividend	
Current quarterly base dividend per share	$0.10
Additional Return of Capital	
% of discretionary excess cash flow [(1)] [(2)]	50%

(1) Discretionary excess cash flow is calculated as excess cash flow less base dividends.

(2) This % is part of a framework that targets to return up to 50% of discretionary excess cash flow to shareholders.

Additional information relating to Crescent Point, including the Company's December 31, 2022 Annual Information Form, which along with other relevant documents are available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

Specified Financial Measures

Throughout this MD&A, the Company uses the terms “total operating netback”, “total netback”, "operating netback", "netback", “adjusted funds flow from operations”, "excess cash flow", "discretionary excess cash flow", "base dividends", "adjusted working capital (surplus) deficiency", “net debt”, “enterprise value”, “net debt to adjusted funds flow from operations”, "net debt as a percentage of enterprise value", “adjusted net earnings from operations”, “adjusted net earnings from operations per share” and “adjusted net earnings from operations per share - diluted”. These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Total operating netback and total netback are historical non-GAAP financial measures. Total operating netback is calculated as oil and gas sales, less royalties, operating and transportation expenses. Total netback is calculated as total operating netback plus realized commodity derivative gains and losses. Total operating netback and total netback are common metrics used in the oil and gas industry and are used to measure operating results to better analyze performance against prior periods on a comparable basis. The most directly comparable financial measure to total operating netback and total netback is oil and gas sales.

The following table reconciles oil and gas sales to total operating netback and total netback:

($ millions)	**2022**	2021	% Change
Oil and gas sales	**4,493.1**	3,206.5	40
Royalties	**(600.9)**	(408.8)	47
Operating expenses	**(713.1)**	(625.3)	14
Transportation expenses	**(139.8)**	(117.7)	19
Total operating netback	**3,039.3**	2,054.7	48
Realized loss on commodity derivatives	**(641.8)**	(360.8)	78
Total netback	**2,397.5**	1,693.9	42

Operating netback and netback are non-GAAP ratios and are calculated as total operating netback and total netback, respectively, divided by total production. Operating netback and netback are common metrics used in the oil and gas industry and are used to measure operating results on a per boe basis.

Base dividends is a historical non-GAAP financial measure and is calculated as dividends declared less special dividends declared as part of the Company’s return of capital framework and adjusted for timing of the dividend record date. Base dividends are based on a framework that targets dividend sustainability at lower commodity prices, allows for flexibility in the capital allocation process and dividend growth over time, and assists in determining the additional return of capital to shareholders as part of the Company’s return of capital framework.

The following table reconciles dividends declared to base dividends:

($ millions)	**2022**	2021	% Change
Dividends declared	**200.6**	47.8	320
Dividend timing adjustment (1)	**(29.0)**	(26.1)	11
Special dividends	**(19.4)**	—	100
Base dividends	**152.2**	21.7	601

(1) Dividends declared where the declaration date and record date are in different periods.

Adjusted funds flow from operations is a capital management measure and is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures funded by the Company. Transaction costs are excluded as they vary based on the Company's acquisition and disposition activity and to ensure that this metric is more comparable between periods. Decommissioning expenditures are discretionary and are excluded as they may vary based on the stage of the Company's assets and operating areas. The most directly comparable financial measure to adjusted funds flow from operations is cash flow from operating activities. Adjusted funds flow from operations is a key measure that assesses the ability of the Company to finance dividends, potential share repurchases, operating activities, capital expenditures and debt repayments. Adjusted funds flow from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. See Note 17 – "Capital Management" in the audited consolidated financial statements for the year ended December 31, 2022 for additional information on the Company's capital management.

Excess cash flow is a historical non-GAAP financial measure and is defined as adjusted funds flow from operations less capital expenditures, payments on lease liability, decommissioning expenditures funded by the Company and other items (excluding net acquisitions and dispositions). The most directly comparable financial measure to excess cash flow disclosed in the Company's financial statements is cash flow from operating activities. Excess cash flow is a key measure that assesses the ability of the Company to finance dividends, potential share repurchases, debt repayments and returns-based growth.

Discretionary excess cash flow is a historical non-GAAP financial measure and is defined as excess cash flow less base dividends. The most directly comparable financial measure to discretionary excess cash flow disclosed in the Company's financial statements is cash flow from operating activities. Discretionary excess cash flow is a key measure that assesses the funds available for reinvestment in the Company’s business or for return of capital to shareholders beyond the base dividend.

The following table reconciles cash flow from operating activities to adjusted funds flow from operations, excess cash flow and discretionary excess cash flow:

($ millions)	**2022**	2021	% Change
Cash flow from operating activities	**2,192.2**	1,495.8	47
Changes in non-cash working capital	**15.0**	(51.6)	(129)
Transaction costs	**5.1**	12.5	(59)
Decommissioning expenditures (1)	**20.1**	20.2	—
Adjusted funds flow from operations	**2,232.4**	1,476.9	51
Capital expenditures	**(1,027.4)**	(676.1)	52
Payments on lease liability	**(20.4)**	(21.2)	(4)
Decommissioning expenditures	**(20.1)**	(20.2)	—
Other items (2)	**(12.3)**	29.0	(142)
Excess cash flow	**1,152.2**	788.4	46
Base dividends	**(152.2)**	(21.7)	601
Discretionary excess cash flow	**1,000.0**	766.7	30

(1) Excludes amounts received from government grant programs.

(2) Other items include, but are not limited to, unrealized gains and losses on equity derivative contracts, sale of long-term investments and transaction costs. Other items exclude net acquisitions and dispositions.

Adjusted working capital (surplus) deficiency is a capital management measure and is calculated as accounts payable and accrued liabilities, dividends payable and long-term compensation liability net of equity derivative contracts, less cash, accounts receivable, prepaids and deposits, including deposit on acquisition. Adjusted working capital (surplus) deficiency is a component of net debt and is a measure of the Company's liquidity.

The following table reconciles adjusted working capital (surplus) deficiency:

($ millions)	**2022**	2021	% Change
Accounts payable and accrued liabilities	**448.2**	450.7	(1)
Dividends payable	**99.4**	43.5	129
Long-term compensation liability (1)	**59.2**	42.6	39
Cash	**(289.9)**	(13.5)	2,047
Accounts receivable	**(327.8)**	(314.3)	4
Prepaids and deposits (2)	**(84.2)**	(7.4)	1,038
Adjusted working capital (surplus) deficiency	**(95.1)**	201.6	(147)

(1) Includes current portion of long-term compensation liability and is net of equity derivative contracts.

(2) Includes deposit on acquisition.

Net debt is a capital management measure and is calculated as long-term debt plus adjusted working capital (surplus) deficiency, excluding the unrealized foreign exchange on translation of US dollar long-term debt. The most directly comparable financial measure to net debt disclosed in the Company's financial statements is long-term debt. Net debt is a key measure of the Company's liquidity.

The following table reconciles long-term debt to net debt:

($ millions)	**2022**	2021	% Change
Long-term debt [(1)]	**1,441.5**	1,970.2	(27)
Adjusted working capital (surplus) deficiency	**(95.1)**	201.6	(147)
Unrealized foreign exchange on translation of US dollar long-term debt	**(191.7)**	(166.8)	15
Net debt	**1,154.7**	2,005.0	(42)

(1) Includes current portion of long-term debt.

Enterprise value is a supplementary financial measure and is calculated as market capitalization plus net debt. Enterprise value is used to assess the valuation of the Company. Refer to the *Liquidity and Capital Resources* section in this MD&A for further information.

Net debt to adjusted funds flow from operations is a capital management measure and is calculated as the period end net debt divided by the sum of adjusted funds flow from operations for the trailing four quarters. Net debt as a percentage of enterprise value is a supplementary financial measure and is calculated as net debt divided by enterprise value. The measures of net debt to adjusted funds flow from operations and net debt as a percentage of enterprise value are used to measure the Company's overall debt position and to measure the strength of the Company's balance sheet. Crescent Point monitors these measures and uses them as key measures in capital allocation decisions including capital spending levels, returns to shareholders including dividends and share repurchases, and financial considerations.

Adjusted net earnings from operations is a historical non-GAAP financial measure and is calculated based on net income before amortization of E&E undeveloped land, impairment or impairment reversals, unrealized derivative gains or losses, unrealized foreign exchange gain or loss on translation of hedged US dollar long-term debt, unrealized gains or losses on long-term investments, gains or losses on the sale of long-term investments, gains or losses on capital acquisitions and dispositions and deferred tax related to these adjustments. Adjusted net earnings from operations is a key measure of financial performance that is more comparable between periods. Adjusted net earnings from operations for the year ended December 31, 2021 also excludes deferred tax related to a change in estimated usable tax pools resulting from a recent potential precedent setting Federal Court case. The most directly comparable financial measure to adjusted net earnings from operations disclosed in the Company's financial statements is net income.

The following table reconciles net income to adjusted net earnings from operations:

($ millions)	**2022**	2021	% Change
Net income	**1,483.4**	2,364.1	(37)
Amortization of E&E undeveloped land	**15.2**	51.0	(70)
Impairment reversal	**(428.6)**	(2,514.4)	(83)
Unrealized derivative (gains) losses	**(171.0)**	141.4	(221)
Unrealized foreign exchange (gain) loss on translation of hedged US dollar long-term debt	**27.7**	(37.0)	(175)
Unrealized gain on long-term investments	**—**	(3.1)	(100)
Gain on sale of long-term investments	**—**	(7.0)	(100)
Net gain on capital dispositions	**(25.9)**	(58.4)	(56)
Deferred tax adjustments	**64.9**	578.7	(89)
Adjusted net earnings from operations	**965.7**	515.3	87

Adjusted net earnings from operations per share and adjusted net earnings from operations per share - diluted are non-GAAP ratios and are calculated as adjusted net earnings from operations divided by the number of weighted average basic and diluted shares outstanding, respectively. Adjusted net earnings from operations presents a measure of financial performance that is more comparable between periods. Adjusted net earnings from operations as presented is not intended to represent net earnings or other measures of financial performance calculated in accordance with IFRS.

Management believes the presentation of the specified financial measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

Forward-Looking Information

Certain statements contained in this management's discussion and analysis constitute forward-looking statements and are based on Crescent Point's beliefs and assumptions based on information available at the time the assumption was made. By its nature, such forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements are effective only as of the date of this report. Crescent Point undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required to do so pursuant to applicable law.

Any “financial outlook” or “future oriented financial information” in this management’s discussion and analysis, as defined by applicable securities legislation, have been approved by management of Crescent Point. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management’s current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

Certain statements contained in this MD&A, including statements related to Crescent Point's capital expenditures, projected asset growth, view and outlook toward future commodity prices, drilling activity and statements that contain words such as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", “projected”, “sustain”, “continues”, “strategy”, “potential”, “projects”, “grow”, “take advantage”, “estimate” and similar expressions and statements relating to matters that are not historical facts constitute "forward-looking information" within the meaning of applicable Canadian securities legislation. The material assumptions and factors in making these forward-looking statements are disclosed in this MD&A under the headings "Overview", "Commodity Derivatives", “Liquidity and Capital Resources” and “Guidance”.

In particular, forward-looking statements include:

- Crescent Point's approach to proactively manage the risk exposure inherent in movements in the price of crude oil, propane, natural gas, the Company's share price, the US/Cdn dollar exchange rate and interest rates through the use of derivatives with investment-grade counterparties;
- Years of inventory in the Kaybob Duvernay play;
- Focus on core areas and long-term sustainability;
- Return of capital framework, targeting the return of up to 50 percent of discretionary excess cash flow, in addition to base dividends, through a combination of share repurchases and dividends;
- Crescent Point's use of derivatives to reduce the volatility of the selling price of its crude oil and natural gas production and how this provides a measure of stability to cash flow;
- The extent and effectiveness of hedges;
- Based on current forecast commodity prices, the Company expects to generate strong returns and cash flow to provide continued returns to shareholders;
- The Company's Canadian gas production generally trading at a slight premium to AECO pricing;
- Crescent Point's 2023 production and capital expenditures guidance, and other information forming part of the 2023 guidance;
- Crescent Point's return of capital outlook including dividend expectations and additional return of capital target as a percentage of discretionary excess cash flow;
- The Company's liquidity and financial flexibility;
- NCIB expectations; and
- Estimated undiscounted and uninflated cash flows to settle decommissioning liability.

This information contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, many of which are beyond Crescent Point's control. Such risks and uncertainties include, but are not limited to: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas, decisions or actions of OPEC and non-OPEC countries in respect of supplies of oil and gas; delays in business operations or delivery of services due to pipeline restrictions, rail blockades, outbreaks, blowouts and business closures and social distancing measures mandated by public health authorities in response to COVID-19, including current and new variants thereof; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on Indigenous lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value and likelihood of acquisitions and dispositions, and exploration and development programs; unexpected geological, technical, drilling, construction, processing and transportation problems; the impact of severe weather events; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions, including uncertainty in the demand for oil and gas and economic activity in general, including as a result of the COVID-19 pandemic; changes in interest rates and inflation; uncertainties associated with regulatory approvals; geopolitical conflicts, including the Russian invasion of Ukraine; uncertainty of government policy changes; the impact of the implementation of the Canada-United States-Mexico Agreement; uncertainty regarding the benefits and costs of dispositions; failure to complete acquisitions and dispositions; uncertainties associated with credit facilities and counterparty credit risk; changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry; the wide-ranging impacts of the COVID-19 pandemic, including on demand, health and supply chain; and other factors, many of which are outside the control of the Company.

Therefore, Crescent Point's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits or detriments Crescent Point will derive therefrom.

Crude oil and condensate, and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 - "Extractive Activities - Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

The Company files its reserves information under National Instrument 51-101 - "Standards of Disclosure of Oil and Gas Activities" (NI 51-101), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission (“SEC”) requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires Company gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards may be material.

Barrels of oil equivalent (“boe”) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil and condensate as compared to natural gas is significantly different from the energy equivalency of oil, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Oil and gas metrics such as operating netback and netback do not have standardized meaning and as such may not be reliable, and should not be used to make comparisons.

Years of corporate inventory figures include proved and probably locations, as derived from the independently evaluated (by McDaniel & Associates Consultants Ltd.) Reserves Report in accordance with NI 51-101 and the COGE Handbook, and additional internally identified net drilling locations.

NI 51-101 includes condensate within the natural gas liquids (NGLs) product type. The Company has disclosed condensate as combined with crude oil and separately from other natural gas liquids in this MD&A since the price of condensate as compared to other natural gas liquids is currently significantly higher and the Company believes that this crude oil and condensate presentation provides a more accurate description of its operations and results therefrom.

The Company’s annual aggregate production for 2022 and 2021, the aggregate production for the past eight quarters and the references to “natural gas”, “crude oil" and "condensate”, reported in this MD&A consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 6 mcf : 1 bbl where applicable:

	2022					2021				
	Annual	Q4	Q3	Q2	Q1	Annual	Q4	Q3	Q2	Q1
Light & Medium Crude Oil (bbl/d)	14,274	13,671	12,347	15,752	15,365	17,859	15,517	15,046	20,181	20,699
Heavy Crude Oil (bbl/d)	4,027	3,870	4,102	4,103	4,034	4,203	4,226	4,199	4,269	4,118
Tight Oil (bbl/d)	53,861	52,095	54,030	53,521	55,837	62,492	55,965	58,233	65,595	70,459
Total Crude Oil (bbl/d)	72,162	69,636	70,479	73,376	75,236	84,554	75,708	77,478	90,045	95,276
NGLs (bbl/d)	36,556	38,893	38,481	34,013	34,774	29,054	33,720	32,904	36,007	13,319
Shale Gas (mcf/d)	130,902	142,803	134,049	119,924	126,622	103,124	115,482	117,339	125,830	53,198
Conventional Natural Gas (mcf/d)	10,482	10,769	10,307	10,800	10,045	11,328	10,389	13,484	9,701	11,534
Total Natural Gas (mcf/d)	141,384	153,572	144,356	130,724	136,667	114,452	125,871	130,823	135,531	64,732
Total (boe/d)	132,282	134,124	133,019	129,176	132,788	132,683	130,407	132,186	148,641	119,384

Directors

Barbara Munroe, Chair [6]

James Craddock [2] [3] [5]

John Dielwart [3] [4]

Ted Goldthorpe [1] [5]

Mike Jackson [1] [5]

Jennifer Koury [2] [5]

Francois Langlois [1] [3] [4]

Myron Stadnyk [2] [3] [4]

Mindy Wight [1] [2]

Craig Bryksa [4]

[1] Member of the Audit Committee of the Board of Directors

[2] Member of the Human Resources and Compensation Committee of the Board of Directors

[3] Member of the Reserves Committee of the Board of Directors

[4] Member of the Environment, Safety and Sustainability Committee of the Board of Directors

[5] Member of the Corporate Governance and Nominating Committee

[6] Chair of the Board serves in an *ex officio* capacity on each Committee

Officers

Craig Bryksa
President and Chief Executive Officer

Ken Lamont
Chief Financial Officer

Ryan Gritzfeldt
Chief Operating Officer

Mark Eade
Senior Vice President, General Counsel and Corporate Secretary

Garret Holt
Senior Vice President, Corporate Development

Michael Politeski
Senior Vice President, Finance and Treasurer

Shelly Witwer
Senior Vice President, Business Development

Justin Foraie
Vice President, Engineering and Marketing

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Calgary, Alberta

Legal Counsel

Norton Rose Fulbright Canada LLP
Calgary, Alberta

Evaluation Engineers

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Investors are encouraged to contact Crescent Point's Registrar and Transfer Agent for information regarding their security holdings:

Computershare Trust Company of Canada
600, 530 - 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Tel: (403) 267-6800

Stock Exchanges

Toronto Stock Exchange - TSX
New York Stock Exchange - NYSE

Stock Symbol

CPG

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Manager, Investor Relations
(403) 693-0020

Exhibit 99.4

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Craig Bryksa, certify that:

1. I have reviewed this annual report of Crescent Point Energy Corp. on Form 40-F;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the period presented in this report;
4. The issuer’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the issuer’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the issuer’s internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer’s internal control over financial reporting; and
5. The issuer’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer’s auditors and the audit committee of the issuer’s board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer’s ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer’s internal control over financial reporting.

Dated: March 2, 2023

CRESCENT POINT ENERGY CORP.

/s/ Craig Bryksa

Name: Craig Bryksa
Title: President and Chief Executive Officer

Exhibit 99.5

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Ken Lamont, certify that:

1. I have reviewed this annual report of Crescent Point Energy Corp. on Form 40-F;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the period presented in this report;
4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and
5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 2, 2023		CRESCENT POINT ENERGY CORP.	
			/s/ Ken Lamont
		Name:	Ken Lamont
		Title:	Chief Financial Officer

Exhibit 99.6

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Crescent Point Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Craig Bryksa, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 2, 2023

CRESCENT POINT ENERGY CORP.

/s/ Craig Bryksa

Name: Craig Bryksa
Title: President and Chief Executive Officer

Exhibit 99.7

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Crescent Point Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ken Lamont, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 2, 2023

CRESCENT POINT ENERGY CORP.

/s/ Ken Lamont

Name: Ken Lamont
Title: Chief Financial Officer

Exhibit 99.8

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in this Annual Report on Form 40-F for the year ended December 31, 2022 of Crescent Point Energy Corp. of our report dated March 1, 2023, relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Exhibit incorporated by reference in this Annual Report.

We also consent to the incorporation by reference in the Registration Statements on Form F-10 (File No. 333-257761) as amended, Form S-8 (File No. 333-226210) and Form F-3D (File No. 333-205592) of Crescent Point Energy Corp. of our report dated March 1, 2023 referred to above. We also consent to reference to us under the heading “Interests of Experts,” which appears in the Annual Information Form included in the Exhibit incorporated by reference in this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants

Calgary, Alberta
Canada

March 1, 2023

Exhibit 99.9

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use of and reference to our name and report evaluating the petroleum and natural gas reserves attributable to Crescent Point Energy Corp's (the "Company") and its affiliates, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs, and the information derived from our reports entitled "Crescent Point Energy Corp, Evaluation of Petroleum Reserves, Based on Forecast Prices and Costs, As at December 31, 2022, dated February 7, 2023", and our report "Crescent Point Energy Corp, Evaluation of Petroleum Reserves, Based on Constant Prices and Costs, As at December 31, 2022, dated February 7, 2023" as described or incorporated by reference in the Company's annual report on Form 40-F for the year ended December 31, 2022 filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2022 dated March 1, 2023, and that we have no reason to believe that there are any misrepresentations in the information contained therein that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

McDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ Michael J. Verney
Michael J. Verney, P.Eng.
Executive Vice President

Calgary, Alberta
March 1, 2023

Exhibit 99.10

Crescent Point Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil & Gas (unaudited)
December 31, 2022

The following disclosures have been prepared by Crescent Point Energy Corp. ("Crescent Point" or the "Company") in accordance with Accounting Standards Codification 932 "Extractive Activities — Oil & Gas" ("ASC 932") issued by the Financial Accounting Standards Board ("FASB") and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

For the years ended December 31, 2022 and 2021, the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using trailing 12-month average prices and current costs; whereas NI 51-101 requires Company gross reserves, before royalties, using forecast pricing and costs. The difference between the reported numbers under the two disclosure standards can, therefore, be material.

Petroleum and Natural Gas Reserve Information

Reserves are estimated quantities of crude oil, NGLs and natural gas anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and considered to be economic at average commodity prices based upon the prior 12-month period. Estimates of petroleum and natural gas reserves are very complex, subject to uncertainty, require significant subjective decisions in the evaluation of all available geological, engineering and economic data, and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change. Net reserves presented in this section represent the Company's working interest and overriding royalty share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

Proved petroleum and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids ("NGL") that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed petroleum and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, which may require future expenditures. Additional future expenditures would be minor compared to the cost of drilling a new well.

Proved undeveloped petroleum and natural gas reserves are reserves that are expected to be recovered from known accumulations where significant future expenditure is required.

Future fluctuations in prices and costs, production rates or changes in political or regulatory environments could cause the Company's reserves to be materially different from that presented.

The changes in Crescent Point's net proved crude oil, NGL and natural gas reserves under constant prices and costs for the two-year period ended December 31, 2022 were as follows:

	Canada				United States				Total			
Net Proved Reserves [(1)]	**Crude Oil (Mbbls)**	**NGLs (Mbbls)**	**Natural Gas (MMcf)**	**Total (Mboe)**	**Crude Oil (Mbbls)**	**NGLs (Mbbls)**	**Natural Gas (MMcf)**	**Total (Mboe)**	**Crude Oil (Mbbls)**	**NGLs (Mbbls)**	**Natural Gas (MMcf)**	**Total (Mboe)**
December 31, 2020	162,431	25,166	99,676	204,210	15,512	5,208	14,411	23,122	177,943	30,375	114,087	227,332
Revisions of previous estimates	44,118	10,044	50,036	62,501	(1,152)	680	4,246	235	42,965	10,724	54,282	62,736
Improved recovery	6,208	313	1,787	6,819	—	—	—	—	6,208	313	1,787	6,819
Purchases of reserves in place	—	48,261	193,763	80,554	—	—	—	—	—	48,261	193,763	80,554
Extensions and discoveries	42,838	33,620	125,850	97,432	16,658	4,672	14,832	23,802	59,496	38,292	140,682	121,235
Production	(22,938)	(8,057)	(37,891)	(37,310)	(3,562)	(1,236)	(3,888)	(5,447)	(26,501)	(9,293)	(41,780)	(42,757)
Sales of reserves in place	(14,824)	(768)	(5,404)	(16,492)	—	—	—	—	(14,824)	(768)	(5,404)	(16,492)
December 31, 2021	217,832	108,579	427,816	397,714	27,456	9,324	29,600	41,713	245,288	117,903	457,416	439,427
Revisions of previous estimates	10,883	504	2,288	11,769	2,442	1,624	4,765	4,861	13,326	2,128	7,054	16,630
Improved recovery	—	—	—	—	—	—	—	—	—	—	—	—
Purchases of reserves in place	—	7,872	54,199	16,905	—	—	—	—	—	7,872	54,199	16,905
Extensions and discoveries	3,999	16,776	80,646	34,216	—	—	—	—	3,999	16,776	80,646	34,216
Production	(19,621)	(10,378)	(47,062)	(37,843)	(3,477)	(1,367)	(3,948)	(5,502)	(23,098)	(11,745)	(51,010)	(43,345)
Sales of reserves in place	(9,560)	(5,973)	(36,770)	(21,661)	—	—	—	—	(9,560)	(5,973)	(36,770)	(21,661)
December 31, 2022	203,534	117,380	481,118	401,100	26,421	9,581	30,417	41,072	229,955	126,961	511,535	442,172
Net Proved Developed Reserves												
December 31, 2020	143,011	22,653	89,037	180,503	15,512	5,208	14,411	23,122	158,523	27,861	103,448	203,625
December 31, 2021	161,205	60,650	268,242	266,562	13,054	5,284	16,774	21,133	174,259	65,934	285,016	287,695
December 31, 2022	156,630	62,226	277,787	265,154	16,602	6,782	21,531	26,973	173,232	69,009	299,318	292,127
Net Proved Undeveloped Reserves												
December 31, 2020	19,420	2,514	10,639	23,707	—	—	—	—	19,420	2,514	10,639	23,707
December 31, 2021	56,627	47,929	159,574	131,152	14,402	4,040	12,826	20,579	71,029	51,970	172,400	151,731
December 31, 2022	46,904	55,153	203,331	135,946	9,819	2,799	8,886	14,099	56,723	57,952	212,217	150,044

(1) Numbers may not add due to rounding.

Revisions of previous estimates - 2021

In 2021, total proved reserves increased by approximately 63.4 MMboe in Canada, and 5.9 MMboe in the United States due to increases in constant pricing for crude oil, natural gas, and NGL constituents at December 31, 2021 compared to December 31, 2020. In the United States, revisions due to pricing were offset by performance related revisions within North Dakota.

Revisions of previous estimates - 2022

In 2022, total proved reserves increased by approximately 19.3 MMboe in Canada, and 2.9 MMboe in the United States due to increases in constant pricing for crude oil, natural gas, and NGL constituents at December 31, 2022 compared to December 31, 2021. Revisions due to higher commodity pricing were offset by revisions due to higher inflationary operating costs.

Purchase of reserves in place - 2021 and 2022

The Company purchased gas and NGL constituent volumes within the Kaybob area in Canada.

Extensions and discoveries - 2021

In 2021, the Company realized significant extension reserves as a result of the addition of previously uneconomic locations due to improved constant pricing.

Extensions and discoveries - 2022

In 2022, the Company added significant extension reserves within the Kaybob area in Canada.

Sale of reserves in place - 2021

In 2021, the Company realized dispositions within Canada including the disposition of Conventional assets within Southeast Saskatchewan and Duvernay assets within Central Alberta.

Sale of reserves in place - 2022

During the year, the Company realized dispositions within Canada including the disposition of assets within Southwest Saskatchewan and East Shale Duvernay.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Petroleum and Natural Gas Reserves

The following information has been developed utilizing procedures prescribed by ASC 932, as updated by Accounting Standards Update 2010-03 "Oil and Gas Reserve Estimation and Disclosures", and based on crude oil, NGL and natural gas reserve and production volumes estimated by Crescent Point's independent reserves evaluators, McDaniel & Associates Consultants Ltd. The methodology used in calculating our price and cost assumptions for the standardized measure of discounted future net cash flows for reserve estimation is based upon the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period.

Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the petroleum and natural gas properties based upon existing laws and regulations. A 10% discount factor was applied to the future net cash flows.

The information contained in the following table should not be considered representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the fair market value of Crescent Point's petroleum and natural gas properties. Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated. The prescribed discount rate of 10% may not appropriately reflect interest rates.

Commodity Pricing	**2022**	**2021**
WTI at Cushing Oklahoma ($US/bbl)	94.14	66.55
Edmonton ($Cdn/bbl)	119.13	78.15
Exchange Rate ($US/$Cdn)	0.7700	0.7980
AECO/NIT Spot ($Cdn/MMBTU)	5.62	3.57
Henry Hub NYMEX ($US/MMBTU)	6.25	3.64

The standardized measure of discounted future net cash flows relating to net proved crude oil, NGL and natural gas reserves are as follows:

December 31, 2022 (millions of Canadian dollars) (1)	**Canada**	**United States**	**Total**
Future cash inflows	34,653	3,519	38,172
Future production costs	(11,226)	(1,127)	(12,353)
Future development costs and asset retirement obligations (2)	(3,967)	(329)	(4,296)
Future income taxes (3)	(3,364)	(159)	(3,523)
Future net cash flows	16,097	1,904	18,001
Deduct: 10% annual discount factor for timing of future cash flows	(6,607)	(549)	(7,156)
Standardized measure of future net cash flows	9,490	1,354	10,845

(1) Numbers may not add due to rounding.

(2) Asset retirement obligations include the costs related to producing wells, future undeveloped proved locations for which there are reserves assigned, as well as all entities that do not have reserves assigned including facilities and gathering systems.

(3) At December 31, 2022, the Company's Canadian and United States tax pools in Canadian dollars were approximately $5.7 billion and $3.0 billion, respectively.

December 31, 2021 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Future cash inflows	23,498	2,306	25,804
Future production costs	(8,558)	(857)	(9,415)
Future development costs and asset retirement obligations [2]	(3,497)	(403)	(3,899)
Future income taxes [3]	(1,239)	(3)	(1,243)
Future net cash flows	10,204	1,043	11,247
Deduct: 10% annual discount factor for timing of future cash flows	(3,716)	(328)	(4,043)
Standardized measure of future net cash flows	6,489	715	7,204

(1) Numbers may not add due to rounding.

(2) Asset retirement obligations include the costs related to producing wells, future undeveloped proved locations for which there are reserves assigned, as well as all entities that do not have reserves assigned including facilities and gathering systems.

(3) At December 31, 2021, the Company's Canadian and United States tax pools in Canadian dollars were approximately $7.0 billion and $2.9 billion, respectively.

Reconciliation of Changes in Standardized Measure of Future Net Cash Flows Discounted at 10% per Year Relating to Proved Petroleum and Natural Gas Reserves

December 31, 2022 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Balance, beginning of year	6,489	715	7,204
Sales, net of production costs and royalties	(2,653)	(387)	(3,039)
Net change in prices and royalties related to forecast production	6,345	918	7,263
Development costs incurred during the period	707	259	966
Changes in estimated future development costs	(250)	(61)	(310)
Extensions, discoveries and improved recovery, net of related costs	1,064	—	1,064
Technical reserve revisions [2]	(227)	216	(11)
Purchases of reserves in place	361	—	361
Sales of reserves in place	(321)	—	(321)
Accretion of discount	714	72	786
Net change in income taxes	(1,191)	(102)	(1,292)
All other changes [3]	(1,549)	(275)	(1,824)
Balance, end of year	9,490	1,354	10,845

(1) Numbers may not add due to rounding.

(2) Includes change in future net values attributed to infill drilling and technical revisions, which include changes to abandonment obligations and carbon tax assumptions.

(3) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, currency exchange rates and actual prices received in 2022 versus forecast. Increases in operating expenses due to heightened inflation make up a large majority of this change.

December 31, 2021 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Balance, beginning of year	1,515	235	1,751
Sales, net of production costs and royalties	(1,789)	(266)	(2,055)
Net change in prices and royalties related to forecast production	3,618	388	4,006
Development costs incurred during the period	505	107	612
Changes in estimated future development costs	(19)	—	(19)
Extensions, discoveries and improved recovery, net of related costs	1,487	394	1,881
Technical reserve revisions [2]	245	(35)	211
Purchases of reserves in place	1,971	—	1,971
Sales of reserves in place	(17)	—	(17)
Accretion of discount	152	24	175
Net change in income taxes	(1,239)	(3)	(1,243)
All other changes [3]	60	(128)	(68)
Balance, end of year	6,489	715	7,204

(1) Numbers may not add due to rounding.

(2) Includes change in future net values attributed to infill drilling and technical revisions, which include changes to abandonment obligations and carbon tax assumptions.

(3) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, currency exchange rates and actual prices received in 2021 versus forecast.

Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

As at December 31, 2022 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Proved properties	20,194	2,145	22,339
Unproved properties	1,162	292	1,454
Total capital costs	21,356	2,437	23,793
Accumulated depletion, amortization and impairment	(14,802)	(1,199)	(16,001)
Net capitalized costs	6,554	1,238	7,792

As at December 31, 2021 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Proved properties	21,655	1,748	23,403
Unproved properties	1,336	277	1,613
Total capital costs	22,991	2,025	25,016
Accumulated depletion, amortization and impairment	(16,274)	(1,053)	(17,327)
Net capitalized costs	6,717	972	7,689

Costs Incurred in Petroleum and Natural Gas Property Acquisitions, Exploration and Development Activities

Year ended December 31, 2022 (millions of Canadian dollars) (1)	**Canada**	**United States**	**Total**
Property acquisition costs (2)			
Proved properties	61	2	63
Unproved properties	28	—	28
Development costs (3)	707	259	966
Exploration costs	9	—	9
Total	805	261	1,066

(1) Numbers may not add due to rounding.

(2) Excludes disposition proceeds of $272.7 million and $10.9 million for proved and unproved properties, respectively.

(3) Costs incurred exclude capitalized administration.

Year ended December 31, 2021 (millions of Canadian dollars) [(1)]	**Canada**	**United States**	**Total**
Property acquisition costs [(2)]			
Proved properties	924	—	924
Unproved properties	19	—	19
Development costs [(3)]	505	107	612
Exploration costs	17	—	17
Total	1,465	107	1,572

(1) Numbers may not add due to rounding.

(2) Excludes disposition proceeds of $93.6 million and $5.4 million for proved and unproved properties, respectively.

(3) Costs incurred exclude capitalized administration.

Results of Operations From Crude Oil and Natural Gas Producing Activities

Year ended December 31, 2022 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Petroleum and natural gas revenues, net of royalties	3,411	481	3,892
Less:			
Operating expenses	628	85	713
Transportation expenses	131	9	140
Depletion and amortization	783	144	927
Impairment reversal	(358)	(71)	(429)
Accretion	19	—	19
Operating income	2,208	314	2,522
Income taxes	—	—	—
Results of operations	2,208	314	2,522

Year ended December 31, 2021 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Petroleum and natural gas revenues, net of royalties	2,450	348	2,798
Less:			
Operating expenses	546	79	625
Transportation expenses	115	3	118
Depletion and amortization	644	116	760
Impairment reversal	(2,077)	(437)	(2,514)
Accretion	15	—	15
Operating income	3,207	587	3,794
Income taxes	—	—	—
Results of operations	3,207	587	3,794

Document and Entity Information	12 Months Ended Dec. 31, 2022 shares
Document Information [Line Items]	
Document Type	40-F
Document Registration Statement	false
Document Annual Report	true
Document Period End Date	Dec. 31, 2022
Current Fiscal Year End Date	--12-31
Entity File Number	001-36258
Entity Registrant Name	CRESCENT POINT ENERGY CORP.
Entity Incorporation, State or Country Code	A0
Entity Primary SIC Number	1311
Entity Address, Address Line Two	Suite 2000
Entity Address, Address Line One	585-8th Avenue S.W.
Entity Address, City or Town	Calgary
Entity Address, State or Province	AB
Entity Address, Postal Zip Code	T2P 1G1
City Area Code	403
Local Phone Number	693-0020
Title of 12(b) Security	Common Shares
Trading Symbol	CPG
Security Exchange Name	NYSE
Annual Information Form	true
Audited Annual Financial Statements	true
Entity Common Stock, Shares Outstanding	550,888,983
Entity Current Reporting Status	Yes
Entity Interactive Data Current	Yes
Entity Emerging Growth Company	false
ICFR Auditor Attestation Flag	true
Amendment Flag	false
Entity Central Index Key	0001545851
Document Fiscal Year Focus	2022
Document Fiscal Period Focus	FY
Business Contact	
Document Information [Line Items]	
Contact Personnel Name	CT Corporation System
Entity Address, Address Line One	111 - 8th Avenue
Entity Address, City or Town	New York
Entity Address, State or Province	NY
Entity Address, Postal Zip Code	10011
City Area Code	212
Local Phone Number	894-8940

Audit Information	12 Months Ended Dec. 31, 2022
Audit Information [Abstract]	
Auditor Name	Chartered Professional Accountants
Auditor Firm ID	271
Auditor Location	Calgary, Canada

Consolidated Balance Sheets - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
ASSETS		
Cash	$ 289.9	$ 13.5
Accounts receivable	327.8	314.3
Deposit on acquisition	18.7	0.0
Prepaids and deposits	65.5	7.4
Derivative asset	138.9	75.7
Assets held for sale	148.4	0.0
Total current assets	989.2	410.9
Derivative asset	96.4	144.8
Other long-term assets	6.4	6.4
Exploration and evaluation	104.2	48.8
Property, plant and equipment	7,729.4	7,687.3
Right-of-use asset	78.1	91.4
Goodwill	203.9	211.5
Deferred income tax	278.8	570.1
Total assets	9,486.4	9,171.2
LIABILITIES		
Accounts payable and accrued liabilities	448.2	450.7
Dividends payable	99.4	43.5
Current portion of long-term debt	538.7	278.1
Derivative liability	8.7	159.6
Other current liabilities	115.6	100.3
Liabilities associated with assets held for sale	28.4	0.0
Total current liabilities	1,239.0	1,032.2
Long-term debt	902.8	1,692.1
Derivative liability	0.0	5.3
Other long-term liabilities	40.8	35.8
Lease liability	99.2	115.9
Decommissioning liability	633.9	884.6
Deferred income tax	77.3	0.0
Total liabilities	2,993.0	3,765.9
SHAREHOLDERS’ EQUITY		
Shareholders’ capital	16,419.3	16,706.9
Contributed surplus	17.1	17.5
Deficit	(10,563.3)	(11,848.7)
Accumulated other comprehensive income	620.3	529.6
Total shareholders' equity	6,493.4	5,405.3
Total liabilities and shareholders' equity	$ 9,486.4	$ 9,171.2

Consolidated Statements of Comprehensive Income - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
REVENUE AND OTHER INCOME		
Revenue from contracts with customers	$ 3,993.0	$ 2,829.4
Commodity derivative losses	(473.4)	(488.9)
Other income	58.8	99.4
Revenue and other income	3,578.4	2,439.9
EXPENSES		
Operating	713.1	625.3
Purchased product	102.9	32.6
Transportation	139.8	117.7
General and administrative	81.8	89.8
Interest	63.6	90.6
Foreign exchange (gain) loss	18.8	(4.4)
Share-based compensation	39.1	30.9
Depletion, depreciation and amortization	951.7	786.1
Impairment reversal	(428.6)	(2,514.4)
Accretion and financing	24.9	21.9
Total Expenses	1,707.1	(723.9)
Net income before tax	1,871.3	3,163.8
Deferred tax expense (recovery):		
Current	0.0	0.0
Deferred	387.9	799.7
Net income	1,483.4	2,364.1
Items that may be subsequently reclassified to profit or loss		
Foreign currency translation adjustment	90.7	11.9
Comprehensive income	$ 1,574.1	$ 2,376.0
Net income per share		
Basic (in cad per share)	$ 2.62	$ 4.15
Diluted (in cad per share)	$ 2.60	$ 4.11
Oil and gas sales		
REVENUE AND OTHER INCOME		
Revenue from contracts with customers	$ 4,493.1	$ 3,206.5
Purchased product sales		
REVENUE AND OTHER INCOME		
Revenue from contracts with customers	100.8	31.7
Royalties		
REVENUE AND OTHER INCOME		
Revenue from contracts with customers	$ (600.9)	$ (408.8)

Consolidated Statement of Changes in Shareholders' Equity - CAD ($) $ in Millions	Total	Shareholders' capital	Contributed surplus	Deficit	Accumulated other comprehensive income
Equity, beginning of year at Dec. 31, 2020	$ 2,822.8	$ 16,451.5	$ 19.7	$ (14,166.1)	$ 517.7
Issued on capital acquisitions	264.5	264.5			
Redemption of restricted shares	0.8	8.5	(8.8)	1.1	
Common shares repurchased for cancellation	(17.5)	(17.5)			
Share issue costs, net of tax	(0.4)	(0.4)			
Share-based compensation	6.8		6.8		
Stock options exercised	0.1	0.3	(0.2)		
Net income	2,364.1			2,364.1	
Dividends ($0.0175 per share 2020; $0.0400 per share 2019)	(47.8)			(47.8)	
Foreign currency translation adjustment	11.9				11.9
Equity, end of year at Dec. 31, 2021	$ 5,405.3	16,706.9	17.5	(11,848.7)	529.6
Dividends (in cad per share)	$ 0.0825				
Redemption of restricted shares	$ 2.6	5.2	(5.2)	2.6	
Common shares repurchased for cancellation	(294.2)	(294.2)			
Share-based compensation	6.2		6.2		
Stock options exercised	0.0	1.4	(1.4)		
Net income	1,483.4			1,483.4	
Dividends ($0.0175 per share 2020; $0.0400 per share 2019)	(200.6)			(200.6)	
Foreign currency translation adjustment	90.7				90.7
Equity, end of year at Dec. 31, 2022	$ 6,493.4	$ 16,419.3	$ 17.1	$ (10,563.3)	$ 620.3
Dividends (in cad per share)	$ 0.3600				

Consolidated Statement of Changes in Shareholders' Equity (Parenthetical) - $ / shares	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Statement of changes in equity [abstract]		
Dividends (in cad per share)	$ 0.3600	$ 0.0825

Consolidated Statements of Cash Flows - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
CASH PROVIDED BY (USED IN):		
Net income	$ 1,483.4	$ 2,364.1
Items not affecting cash		
Other income	(49.0)	(97.0)
Deferred tax expense	387.9	799.7
Share-based compensation	6.0	6.1
Depletion, depreciation and amortization	951.7	786.1
Impairment reversal	(428.6)	(2,514.4)
Accretion	19.2	15.4
Unrealized (gains) losses on derivatives	(171.0)	141.4
Translation of US dollar long-term debt	91.5	(37.0)
Realized gain on cross currency swap maturity	(63.8)	0.0
Decommissioning expenditures	(20.1)	(20.2)
Changes in non-cash working capital:	(15.0)	51.6
Cash flows from (used in) operations	2,192.2	1,495.8
INVESTING ACTIVITIES		
Development capital and other expenditures	(1,027.4)	(676.1)
Capital acquisitions	(90.7)	(677.9)
Capital dispositions	283.6	99.0
Deposit on acquisition	(18.7)	0.0
Sale of long-term investments	0.0	12.6
Changes in non-cash working capital:	(7.4)	49.0
Cash flows from (used in) investing activities	(860.6)	(1,193.4)
FINANCING ACTIVITIES		
Share issue costs	0.0	(0.7)
Common shares repurchased for cancellation	294.2	17.5
Decrease in bank debt, net	(338.5)	(34.6)
Repayment of senior guaranteed notes	(281.8)	(217.6)
Realized gain on cross currency swap maturity	63.8	0.0
Payments on principal portion of lease liability	(20.4)	(21.2)
Dividends declared	(200.6)	(47.8)
Change in non-cash working capital	15.7	42.2
Cash flows from (used in) financing activities	(1,056.0)	(297.2)
Impact of foreign currency on cash balances	0.8	(0.5)
INCREASE IN CASH	276.4	4.7
CASH AT BEGINNING OF YEAR	13.5	8.8
CASH AT END OF YEAR	289.9	13.5
Supplemental Information [Abstract]		
Cash taxes paid	0.0	0.0
Cash interest paid	$ (68.0)	$ (93.1)

Structure of the Business	12 Months Ended Dec. 31, 2022
Corporate Information And Statement of IFRS Compliance [Abstract]	
Structure of the Business	STRUCTURE OF THE BUSINESS The principal undertaking of Crescent Point Energy Corp. (the “Company” or “Crescent Point”) is to carry on the business of acquiring, developing and holding interests in petroleum and natural gas properties and assets related thereto through a general partnership and wholly owned subsidiaries. Crescent Point is the ultimate parent and is amalgamated in Alberta, Canada under the Alberta Business Corporations Act. The address of the principal place of business is 2000, 585 - 8th Ave S.W., Calgary, Alberta, Canada, T2P 1G1. These annual consolidated financial statements were approved and authorized for issue by the Company's Board of Directors on March 1, 2023.

Basis of Preparation	12 Months Ended Dec. 31, 2022
Corporate Information And Statement of IFRS Compliance [Abstract]	
Basis of Preparation	BASIS OF PREPARATION

a) Preparation

These consolidated financial statements are presented under International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board (“IASB”). The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of March 1, 2023, the date the Board of Directors approved the statements.

The Company’s presentation currency is Canadian dollars and all amounts reported are Canadian dollars unless noted otherwise. References to “US$” and "US dollars" are to United States ("U.S.") dollars. Crescent Point's Canadian and U.S. operations are aggregated into one reportable segment based on similar economic characteristics and the similar nature of the assets, products, production processes and customers.

b) Basis of measurement, functional and presentation currency

The Company’s presentation currency is Canadian dollars. The accounts of the Company’s foreign operations that have a functional currency different from the Company’s presentation currency are translated into the Company’s presentation currency at period end exchange rates for assets and liabilities and at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income as cumulative translation adjustments.

c) Use of estimates and judgments

The preparation of consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected.

The Company also faces uncertainties related to future environmental laws and climate-related regulations, which could affect the Company's financial position and future earnings. This transition to a lower-carbon society, as well as the physical impacts of climate change, could result in increased operating costs and reduced demand for oil and gas products. As a result, this could change a number of variables and assumptions used to determine the estimated recoverable amounts of the Company's oil and gas assets. The unpredictable nature, timing and extent of climate-related initiatives presents various risks and uncertainties, including to management's judgements, estimates and assumptions that affect the application of accounting policies. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below.

Oil and gas activities

Reserves estimates, although not reported as part of the Company’s consolidated financial statements, can have a significant effect on net income, assets and liabilities as a result of their impact on depletion, depreciation and amortization (“DD&A”), decommissioning liability, deferred taxes, asset impairments and impairment reversals, and business combinations. Independent petroleum reservoir engineers perform evaluations of the Company’s oil and gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

For purposes of impairment testing, property, plant and equipment (“PP&E”) is aggregated into cash-generating units (“CGUs”), based on separately identifiable and largely independent cash inflows. The determination of the Company’s CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructure, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations.

The determination of technical feasibility and commercial viability, based on the presence of reserves and which results in the transfer of assets from exploration and evaluation ("E&E") to PP&E, is subject to judgment.

Decommissioning liability

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are impacted by estimates with respect to the cost and timing of decommissioning.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Fair value measurement

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of derivative instruments include forward benchmark prices, discount rates, share price, forward foreign exchange rates and forward interest rates.

Joint control

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the capital and operating activities of the projects it undertakes with partners and when the decisions in relation to those activities require unanimous consent.

Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax assets and liabilities recognize the extent that temporary differences will be receivable and payable in future periods. The calculation of the asset and liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, expected cash flows from estimated proved plus probable reserves and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

Significant Accounting Policies	12 Months Ended Dec. 31, 2022
Corporate Information And Statement of IFRS Compliance [Abstract]	
Significant Accounting Policies	SIGNIFICANT ACCOUNTING POLICIES The accounting policies set out below have been applied consistently by the Company and its subsidiaries for all periods presented in these annual consolidated financial statements. **a) Principles of Consolidation** The consolidated financial statements include the accounts of the Company and its subsidiaries and any reference to the “Company” throughout these consolidated financial statements refers to the Company and its subsidiaries. All transactions between the Company and its subsidiaries have been eliminated. The Company conducts some of its oil and gas production activities through jointly controlled operations and the financial statements reflect only the Company's proportionate interest in such activities. Joint control exists for contractual arrangements governing the Company's assets whereby the Company has less than 100 percent working interest, all the partners have control of the arrangement collectively, and share the associated risks. The Company does not have any joint arrangements that are material to the Company or that are structured through joint venture arrangements. **b) Property, Plant and Equipment** Items of PP&E, which primarily consist of oil and gas development and production assets, are measured at cost less accumulated depletion, depreciation and any accumulated impairment losses or impairment reversals. Development and production assets are accumulated into CGUs and account for the cost of developing the commercial reserves and initiating production. Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as development and production assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in net income as incurred. Capitalized development and production assets generally represent costs incurred in developing reserves and initiating or enhancing production from such reserves. The carrying amount of any sold component is derecognized. **Depletion and Depreciation** Development and production assets are depleted using the unit-of-production method based on estimated proved plus probable reserves before royalties, as determined by independent petroleum reservoir engineers. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proved plus probable reserves. Corporate assets are depreciated on a straight line basis over the estimated useful lives of the related assets, ranging from 5 to 16 years.

Impairment

The carrying amounts of PP&E, which takes into account the discounted abandonment and reclamation costs on proved plus probable undeveloped oil and gas reserves, are grouped into CGUs and reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income.

Assets are grouped into CGUs based on the integration between assets, shared infrastructure, the existence of common sales points, geography, geological structure and the manner in which management monitors and makes decisions regarding operations. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent petroleum reservoir engineers. The recoverable amount is the higher of fair value less costs of disposal and the value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate. The fair value less costs of disposal and value in use estimates are categorized as Level 3 according to the IFRS 13 fair value hierarchy.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined, net of depletion, had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net income.

c) Exploration and Evaluation

Exploration and evaluation assets are comprised of the accumulated expenditures incurred in an area where technical feasibility and commercial viability has not yet been determined. Exploration and evaluation assets include undeveloped land and any drilling costs thereon.

Technical feasibility and commercial viability are considered to be determinable when reserves are discovered. Upon determination of reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E.

Costs incurred prior to acquiring the legal rights to explore an area are expensed as incurred.

Amortization

Undeveloped land classified as E&E assets is amortized by major area over the average primary lease term and recognized in net income. Drilling costs classified as E&E assets are not amortized, but are subject to impairment.

Impairment

Exploration and evaluation assets are reviewed quarterly for indicators of impairment and upon reclassification from E&E assets to PP&E. Exploration and evaluation assets are tested for impairment at the operating segment level by combining E&E assets with PP&E. The recoverable amount is the greater of fair value less costs of disposal or value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves, plus the fair market value of undeveloped land. Value-in-use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate.

Impairments of E&E assets are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been, net of amortization, had no impairment been recognized.

d) Decommissioning Liability

The Company recognizes the present value of a decommissioning liability in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis using the relevant risk free rate, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the underlying proved plus probable reserves. Accretion expense is recognized in net income. Revisions to the discount rate, estimated timing or amount of future cash flows would also result in an increase or decrease to the decommissioning liability and related asset.

e) Goodwill

The Company records goodwill relating to business combinations when the purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The goodwill balance is assessed for impairment annually or as events occur that could result in impairment. Goodwill is tested for impairment at an operating segment level by combining the carrying amounts of PP&E, E&E assets and goodwill and comparing this to the recoverable amount. Any excess of the carrying amount over the recoverable amount is the impairment amount. The recoverable amount estimates is categorized as Level 3 according to the IFRS 13 fair value hierarchy. Impairment charges, which are not tax affected, are recognized in net income. Goodwill is reported at cost less any accumulated impairment. Goodwill impairments are not reversed.

f) Share-based Compensation

Restricted shares granted under the Restricted Share Bonus Plan are accounted for at fair value and vest on terms up to three years from the grant date determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and recognized when they occur. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the portion of share-based compensation directly attributable to development activities, with a corresponding decrease to share-based compensation expense. At the time the restricted shares vest, the issuance of shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

Employee Share Value Plan ("ESVP") awards are accounted for at fair value and vest on terms of up to three years from the grant date as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the ESVP awards on the date of grant and subsequently adjusted to reflect the fair value at each period end. The expense is recognized over the service period, with a corresponding increase to long-term compensation liability. ESVP awards are settled in cash upon vesting based on the prevailing Crescent Point share price and the aggregate amount of dividends paid from the grant date.

Performance share units ("PSUs") are accounted for at fair value and vest on terms of up to three years from the grant date as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the PSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Market performance conditions are factored into the fair value and the best estimate of non-market performance conditions is used to determine an estimate of the number of units that will vest. Fair value is based on the expected cash payment per PSU and the expected number of PSUs to vest, calculated from multipliers based on internal and external performance metrics. The expense is recognized over the service period, with a corresponding increase to long-term compensation liability. PSUs are settled in cash upon vesting based on the prevailing Crescent Point share price, the aggregate amount of dividends paid from the grant date and the performance multipliers.

Deferred share units (“DSUs”) are accounted for at fair value. Share-based compensation expense is determined based on the estimated fair value of the DSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Fair value is based on the prevailing Crescent Point share price.

Stock options are accounted for at fair value and have a maximum term of seven years and vest on terms as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the stock options on the date of the grant. Upon vesting, the stock option holder may either exercise their stock options to purchase one common share per option at the exercise price or, at the Company's discretion, surrender their stock options for a cash payment in an amount equal to the aggregate positive difference, if any, between the market price and the exercise price of the number of common shares associated with the stock options surrendered. Alternatively, the stock option holder may also, at the Company's discretion, surrender their stock options for common shares having a value equivalent to the cash payment.

g) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the estimated effect of any differences between the accounting and tax basis of assets and liabilities, using enacted or substantively enacted income tax rates expected to apply when the deferred tax asset or liability is settled. The effect of a change in income tax rates on deferred income taxes is recognized in net income in the period in which the change occurs.

The tax expense for the period comprises current and deferred tax. Tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity. In this case, the tax is also recognized in other comprehensive income or directly in equity, respectively.

The Company is able to deduct certain settlements under its Restricted Share Bonus Plan. To the extent the tax deduction exceeds the cumulative remuneration cost for a particular restricted share grant recorded in net income, the tax benefit related to the excess is recorded directly within equity.

A deferred tax asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized. Deferred income tax assets and liabilities are presented as non-current.

h) Financial Instruments

The Company uses financial derivative instruments and physical delivery commodity contracts from time to time to reduce its exposure to fluctuations in commodity prices, share price, foreign exchange rates and interest rates. The Company also makes investments in companies from time to time in connection with the Company's acquisition and divestiture activities.

Financial derivative instruments

Financial derivative instruments are included in current assets/liabilities except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets/liabilities.

The Company has not designated any of its financial derivative contracts as effective accounting hedges and, accordingly, fair values its financial derivative contracts with the resulting gains and losses recorded in net income.

The fair value of a financial derivative instrument on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair values are based on quoted market prices where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at the reporting date.

Financial assets and liabilities

Financial assets and liabilities are measured at fair value on initial recognition. For non-equity instruments, measurement in subsequent periods depends on the classification of the financial asset or liability as "fair value through profit or loss" or "amortized cost".

Financial assets and liabilities classified as fair value through profit or loss are subsequently carried at fair value, with changes recognized in net income.

Financial assets and liabilities classified as amortized cost are subsequently carried at amortized cost using the effective interest rate method.

Currently, the Company classifies all non-equity financial instruments which are not financial derivative instruments as amortized cost.

At each reporting date, the Company assesses whether there is objective evidence that a financial asset carried at amortized cost is impaired. If such evidence exists, the Company recognizes an impairment loss in net income. Impairment losses are reversed in subsequent periods if the impairment loss decrease can be related objectively to an event occurring after the impairment was recognized.

For investments in equity instruments, the subsequent measurement is dependent on the Company's election to classify such instruments as fair value through profit or loss or fair value through other comprehensive income. Currently, the Company classifies all investments in equity instruments as fair value through profit or loss, whereby the Company recognizes movements in the fair value of the investment (adjusted for dividends) in net income. If the fair value through other comprehensive income classification is selected, the Company would recognize any dividends from the investment in net income and would recognize fair value re-measurements of the investment in other comprehensive income.

Impairment of financial assets

Impairment losses are recognized using an expected credit loss model. The Company has adopted the simplified expected credit loss model for its accounts receivable, which permits the use of the lifetime expected loss provision.

To measure the expected credit losses, accounts receivable have been grouped based on shared credit risk characteristics and days past due. The Company uses judgment in making these assumptions and selecting the inputs into the expected loss calculation based on past history, existing market conditions and forward looking estimates at the end of each reporting period.

i) Business Combinations

Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The consideration paid of an acquisition is measured as the fair value of the acquired assets by estimating the discounted after-tax future net cash flows, the fair value of equity instruments issued and the fair value of liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in net income. Transaction costs associated with business combinations are expensed as incurred.

j) Foreign Currency Translation

Foreign operations

The Company has operations in the U.S. transacted via U.S. subsidiaries. The assets and liabilities of foreign operations are translated to Canadian dollars at exchange rates in effect at the balance sheet date. The income and expenses of foreign operations are translated to Canadian dollars using average exchange rates for the period. The resulting unrealized gain or loss is included in other comprehensive income.

Foreign transactions

Transactions in foreign currencies not incurred by the Company’s U.S. subsidiaries are translated to Canadian dollars at exchange rates in effect at the transaction dates. Foreign currency assets and liabilities are translated to Canadian dollars at exchange rates in effect at the balance sheet date and income and expenses are translated to Canadian dollars using average exchange rates for the period. Both realized and unrealized gains and losses resulting from the settlement or restatement of foreign currency transactions are included in net income.

k) Revenue Recognition

The Company’s major revenue sources are comprised of sales from the production of crude oil and condensate, natural gas liquids ("NGLs") and natural gas. Revenue is recognized when control of the product transfers to the customer and the collection is reasonably probable, generally upon delivery of the product. Sales of crude oil and condensate, NGLs and natural gas production are based on variable pricing as the transaction prices are based on benchmark commodity prices and other variable factors, including quality differentials and location.

Each contract is evaluated based on the nature of the performance obligations, including the Company’s role as either principal or agent. Where the Company acts as principal, revenue is recognized on a gross basis. Where the Company acts as agent, revenue is recognized on a net basis.

l) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with original maturities of three months or less.

m) Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the commencement date, the lease liability is recognized at the present value of the future lease payments and discounted using the interest rate implicit in the lease or the Company's incremental borrowing rate. A corresponding right-of-use ("ROU") asset will be recognized at the amount of the lease liability, adjusted for any lease incentives received and initial direct costs incurred. Over the term of the lease, financing expense is recognized on the lease liability using the effective interest rate method and charged to net income, lease payments are applied against the lease liability and depreciation on the ROU asset is recorded by class of underlying asset.

The lease term is the non-cancellable period of a lease and includes periods covered by an optional lease extension option if reasonably certain the Company will exercise the option to extend. Conversely, periods covered by an option to terminate are included if the Company does not expect to end the lease during that time frame. Leases with a term of less than twelve months or leases for underlying low value assets are recognized as an expense in net income on a straight-line basis over the lease term.

A lease modification will be accounted for as a separate lease if it materially changes the scope of the lease. For a modification that is not a separate lease, on the effective date of the lease modification, the Company will remeasure the lease liability and corresponding ROU asset using the interest rate implicit in the lease or the Company's incremental borrowing rate. Any variance between the remeasured ROU asset and lease liability will be recognized as a gain or loss in net income to reflect the change in scope.

The Company also acts as an intermediate lessor for office space sub-leased to other companies. As a lessor, the Company will evaluate whether a lease is a finance or operating lease. Leases where the Company transfers substantially all the risks and rewards of ownership are classified as finance leases. Conversely, leases where the risks and rewards of ownership are retained by the Company are operating leases. The head lease between the Company and the building, and the sub-lease between the Company and tenants, are accounted for separately. The lease classification of the sub-lease is based upon the head lease and not the underlying asset.

n) Earnings Per Share

Basic earnings per share ("EPS") is calculated by dividing the net income for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period.

Diluted EPS is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to dilutive instruments, being restricted shares issued under the Company's Restricted Share Bonus Plan and stock options under the Company's Stock Option Plan, is computed using the treasury stock method. The treasury stock method assumes that the deemed proceeds related to unrecognized share-based compensation are used to repurchase shares at the average market price during the period.

o) Government Grants

The Company may receive government grants which provide immediate financial assistance as compensation for costs or expenditures to be incurred. Government grants are accounted for when there is reasonable assurance that conditions attached to the grants are met and that the grants will be received. The Company recognizes government grants in net income on a systematic basis and in line with recognition of the expense that the grants are intended to compensate.

p) Assets Held for SalePP&E and E&E assets are classified as held for sale if it is highly probable their carrying amounts will be recovered through a capital disposition rather than through future operating cash flows. Before PP&E and E&E assets are classified as held for sale, they are assessed for indicators of impairment or reversal of previously recorded impairments and are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment charges or reversals are recognized in net income. Assets held for sale are classified as current assets and are not subject to DD&A. Decommissioning liabilities associated with assets held for sale are classified as current liabilities.

Changes in Accounting Policies	12 Months Ended Dec. 31, 2022
Disclosure of changes in accounting policies [Abstract]	
Changes In Accounting Policies	CHANGES IN ACCOUNTING POLICIES **New accounting standards and amendments not yet adopted** ***Income Taxes*** IAS 12 *Income Taxes* was amended in May 2021 by the IASB which requires companies, on initial recognition, to recognize deferred tax on transactions that result in equal amounts of taxable and deductible temporary differences. The amendment is effective for fiscal years beginning on or after January 1, 2023. ***Presentation of Financial Statements*** IAS 1 *Presentation of Financial Statements* was amended in January 2020 by the IASB to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. This amendment is effective for fiscal years beginning on or after January 1, 2024.

Other Long-term Assets	12 Months Ended Dec. 31, 2022
Subclassifications of assets, liabilities and equities [abstract]	
Other Long-term Assets	OTHER LONG-TERM ASSETSAt December 31, 2022, other long-term assets relate to investment tax credits of $6.4 million (December 31, 2021 - $6.4 million).

Exploration and Evaluation Assets	12 Months Ended Dec. 31, 2022
Exploration For And Evaluation Of Mineral Resources [Abstract]	
Exploration and Evaluation Assets	EXPLORATION AND EVALUATION ASSETS

($ millions)	2022
Exploration and evaluation assets at cost	1,453.4
Accumulated amortization	(1,349.2)
Net carrying amount	104.2
Reconciliation of movements during the year	
Cost, beginning of year	1,613.3
Accumulated amortization, beginning of year	(1,564.5)
Net carrying amount, beginning of year	48.8
Net carrying amount, beginning of year	48.8
Acquisitions through business combinations	28.0
Additions	134.2
Dispositions	(10.9)
Transfers to property, plant and equipment	(80.8)
Amortization	(15.2)
Foreign exchange	0.1
Net carrying amount, end of year	104.2

Impairment test of exploration and evaluation assets

There were no indicators of impairment at December 31, 2022 or December 31, 2021.

Capital Acquisitions and Dispositions	12 Months Ended Dec. 31, 2022
Business Combinations And Dispositions [Abstract]	
Capital Acquisitions and Dispositions	

CAPITAL ACQUISITIONS AND DISPOSITIONS

In the year ended December 31, 2022, the Company incurred $5.1 million (year ended December 31, 2021 - $12.5 million) of transaction costs rela business combinations and dispositions that were recorded as general and administrative expenses.

a) Major property acquisitions and dispositions

Saskatchewan Viking disposition

On July 6, 2022, the Company disposed of its non-core Saskatchewan Viking assets for consideration of $241.7 million. These assets had a net ca $219.1 million, resulting in a gain of $22.6 million.

Kaybob Duvernay acquisition

On August 31, 2022, the Company acquired certain Kaybob Duvernay assets for total consideration of $87.0 million.

b) Minor property acquisitions and dispositions

In the year ended December 31, 2022, the Company completed minor property acquisitions and dispositions for net consideration received of $38. a net carrying value of $34.9 million, resulting in a gain of $3.3 million.

The following table summarizes the major and minor property acquisitions and dispositions:

($ millions)	Saskatchewan Viking Disposition	Kaybob Duverna Acquisitio
Cash	241.7	(87.
Consideration (paid) received	**241.7**	**(87.**
Exploration and evaluation	—	28.
Property, plant and equipment	(252.5)	61.
Goodwill	(6.8)	–
Decommissioning liability	40.2	(2.
Fair value of net assets acquired (Carrying value of net assets disposed)	**(219.1)**	**87.**
Gain on capital dispositions	**22.6**	**–**

c) Assets held for sale

At December 31, 2022, the Company classified certain non-core assets in Alberta as held for sale. These assets were recorded at the lesser of the recoverable amount.

($ millions)	**PP&E** (Note 8)
Assets (liabilities) held for sale	**148.4**

Property, Plant and Equipment	12 Months Ended Dec. 31, 2022
Property, plant and equipment [abstract]	
Property, Plant and Equipment	PROPERTY, PLANT AND EQUIPMENT

($ millions)	2022
Development and production assets	22,340.0
Corporate assets	126.2
Property, plant and equipment at cost	22,466.2
Accumulated depletion, depreciation and impairment	(14,736.8)
Net carrying amount	7,729.4
Reconciliation of movements during the year	
Development and production assets	
Cost, beginning of year	23,402.9
Accumulated depletion and impairment, beginning of year	(15,762.6)
Net carrying amount, beginning of year	7,640.3
Net carrying amount, beginning of year	7,640.3
Acquisitions through business combinations	66.0
Additions	741.9
Dispositions	(285.8)
Transfers from exploration and evaluation assets	80.8
Reclassified as assets held for sale	(148.4)
Depletion	(911.4)
Impairment reversal	428.6
Foreign exchange	76.2
Net carrying amount, end of year	7,688.2
Cost, end of year	22,340.0
Accumulated depletion and impairment, end of year	(14,651.8)
Net carrying amount, end of year	7,688.2
Corporate assets	
Cost, beginning of year	123.2
Accumulated depreciation, beginning of year	(76.2)
Net carrying amount, beginning of year	47.0
Net carrying amount, beginning of year	47.0
Additions	2.6
Depreciation	(8.5)
Foreign exchange	0.1
Net carrying amount, end of year	41.2
Cost, end of year	126.2
Accumulated depreciation, end of year	(85.0)
Net carrying amount, end of year	41.2

At December 31, 2022, future development costs of $5.16 billion (December 31, 2021 - $4.58 billion) were included in costs subject to depletion.

Direct general and administrative costs capitalized by the Company during the year ended December 31, 2022 were $49.7 million (year ended Dec
million), including $14.7 million of share-based compensation costs (year ended December 31, 2021 - $14.3 million).

Q4 2022 Impairment

At December 31, 2022, there were no indicators of impairment or impairment reversal in the Alberta and Northern U.S. CGUs.

At December 31, 2022, the Company identified indicators that its Southeast Saskatchewan and Southwest Saskatchewan CGUs might be impaired
costs in the current inflationary environment and the reallocation of forecast capital spending from Saskatchewan to Alberta and Northern U.S., sin
at March 31, 2022, were considered indicators of impairment. As a result, a test for impairment was conducted and the Company prepared estimat
determine the recoverable amount of the respective assets.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at Decem

	2023 (1)	2024	2025	2026	2027	2028	2029	2030	2
WTI ($US/bbl) (2)	80.33	78.50	76.95	77.61	79.16	80.74	82.36	84.00	85
Exchange Rate ($US/$Cdn)	0.745	0.765	0.768	0.772	0.775	0.775	0.775	0.775	0.7
WTI ($Cdn/bbl)	107.83	102.61	100.20	100.53	102.14	104.18	106.27	108.39	110
AECO ($Cdn/mmbtu) (2)	4.23	4.40	4.21	4.27	4.34	4.43	4.51	4.60	4

(1) Effective January 1, 2023.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2033 to the end of the reserve life. Exchange rates are assumed to be constant at 0.775.

At December 31, 2022, the Company determined that the carrying amount of the Southeast Saskatchewan and Southwest Saskatchewan CGUs e
amount. The full amounts of the impairments were attributed to PP&E and, as a result, impairment losses of $985.0 million were recognized in net
loss was due to the increase in forecast costs as a result of the high inflationary environment and the reallocation of forecast capital spending ment

At December 31, 2022, the after tax impairments that can be reversed in future periods for each CGU, net of depletion had no impairment loss bee
periods, were $1.49 billion for Southeast Saskatchewan, $1.09 billion for Southwest Saskatchewan, and nil for Alberta and Northern U.S.

The following table summarizes the impairment expense for the year ended December 31, 2022 by CGU:

CGU ($ millions, except %)	Operating segment	Recoverable amount	Discount rate	Impairme
Southeast Saskatchewan	Canada	2,868.3	15.00 %	564.
Southwest Saskatchewan	Canada	1,356.6	15.00 %	420.
Total impairment		4,224.9		985.

Changes in any of the key judgments, such as a revision in reserves, changes in forecast benchmark commodity prices, foreign exchange rates, di
operating costs would impact the recoverable amounts of assets and any reversals or impairment charges would affect net income. The following s
resulting impact on income before tax of the changes in discount rate, forecast benchmark commodity price and forecast operating cost estimates a
all other variables held constant:

CGU	Discount Rate		Commodity Prices		Op
($ millions)	Increase 1%	Decrease 1%	Increase 5%	Decrease 5%	Increase
Southeast Saskatchewan	(167.8)	185.2	349.4	(348.3)	(11
Southwest Saskatchewan	(88.0)	97.3	185.6	(185.3)	(6
Increase (decrease)	(255.8)	282.5	535.0	(533.6)	(18

Q1 2022 Impairment Reversal

At March 31, 2022, the significant increase in forecast benchmark commodity prices and the increase in the Company's market capitalization since
June 30, 2021, were indicators of impairment reversal.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at March

	2022 (1)	2023	2024	2025	2026	2027	2028	2029	2
WTI ($US/bbl) (2)	94.17	84.05	75.38	74.41	75.90	77.42	78.97	80.55	82
Exchange Rate ($US/$Cdn)	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.8
WTI ($Cdn/bbl)	117.71	105.06	94.23	93.01	94.88	96.78	98.71	100.69	102
AECO ($Cdn/mmbtu) (2)	5.18	4.18	3.38	3.34	3.41	3.48	3.54	3.61	3

(1) Effective April 1, 2022.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2032 to the end of the reserve life. Exchange rates are assumed to be constant at 0.800.

At March 31, 2022, the Company determined that the recoverable amount of the Southeast Saskatchewan, Southwest Saskatchewan, Alberta and exceeded their carrying amount. The full amounts of the impairment reversals were attributed to PP&E and, as a result, impairment reversals of $1 in net income.

The following table summarizes the impairment reversal for the three months ended March 31, 2022 by CGU:

CGU ($ millions, except %)	Operating segment	Recoverable amount	Discount rate	Impairment revers
Southeast Saskatchewan	Canada	3,413.8	15.00 %	806.
Southwest Saskatchewan	Canada	1,715.0	15.00 %	419.
Alberta	Canada	2,567.1	15.00 %	244.
Northern U.S.	U.S.	1,093.8	15.00 %	71.
Total impairment reversal		8,789.7		1,540.

The following sensitivities show the resulting impact on income before tax of the changes in discount rate and forecast benchmark commodity price 2022, with all other variables held constant:

CGU	Discount Rate		Com
($ millions)	Increase 1%	Decrease 1%	Increase
Southeast Saskatchewan	(186.2)	204.8	36
Southwest Saskatchewan	(95.0)	104.6	20
Alberta	—	—	
Northern U.S.	—	—	
Increase (decrease)	(281.2)	309.4	56

2021 Impairment Reversal

At December 31, 2021, there were no indicators of impairment or impairment reversal.

At June 30, 2021, the significant increase in forecast benchmark commodity prices and the increase in the Company's market capitalization since t March 31, 2020 were indicators of impairment reversal.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at June 3

	2021 (1)	2022	2023	2024	2025	2026	2027	2028	2
WTI ($US/bbl) (2)	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	69
Exchange Rate ($US/$Cdn)	0.803	0.802	0.800	0.800	0.800	0.800	0.800	0.800	0.8
WTI ($Cdn/bbl)	88.83	83.79	79.94	79.04	80.63	82.24	83.88	85.55	87
AECO ($Cdn/mmbtu) (2)	3.46	3.13	2.72	2.71	2.76	2.82	2.88	2.94	2

(1) Effective July 1, 2021.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2031 to the end of the reserve life. Exchange rates are assumed to be constant at 0.800.

The following table summarizes the impairment reversal for the six months ended June 30, 2021 by CGU:

CGU ($ millions, except %)	Operating segment	Recoverable amount	Discount rate	Impairment rever
Southeast Saskatchewan	Canada	2,941.0	15.00 %	91
Southwest Saskatchewan	Canada	1,422.6	15.00 %	60
Alberta (1)	Canada	1,911.9	15.00 %	55
Northern U.S.	U.S.	861.9	15.00 %	43
Total impairment reversal		7,137.4		2,51

(1) Previously referred to as the Southern Alberta CGU.

The following sensitivities show the resulting impact on income before tax of the changes in discount rate and forecast benchmark commodity price
2021, with all other variables held constant:

CGU	Discount Rate		Com
($ millions)	Increase 1%	Decrease 1%	Increase
Southeast Saskatchewan	(181.1)	199.2	35
Southwest Saskatchewan	(89.1)	97.9	18
Alberta [1]	(89.4)	97.2	18
Northern U.S.	(57.1)	62.9	12
Increase (decrease)	(416.7)	457.2	84

(1) Previously referred to as the Southern Alberta CGU.

Goodwill	12 Months Ended Dec. 31, 2022

Subclassifications of assets, liabilities and equities [abstract]

Goodwill

GOODWILL

($ millions)	2022
Goodwill, beginning of year	**211.5**
Southeast Saskatchewan asset disposition	**—**
Saskatchewan Viking asset disposition	**(6.8)**
Other dispositions	**(0.8)**
Goodwill, end of year	**203.9**

Goodwill has been assigned to the Canadian operating segment.

Impairment test of goodwill

The impairment tests of goodwill compared the recoverable amount of the Company's PP&E and E&E to the carrying amount of the combined PP&
December 31, 2022 and December 31, 2021. The recoverable amount of the Company's PP&E and E&E was estimated using independent reserve
benchmark commodity prices, proved plus probable reserve estimates and management's estimate of the fair market value of undeveloped land. S
and Evaluation Assets" and Note 8 - "Property, Plant and Equipment" for additional information. As a result of these tests, the Company concluded
recoverable amounts exceeded the carrying amounts and no impairments were recorded.

Other Current Liabilities	12 Months Ended Dec. 31, 2022
Subclassifications of assets, liabilities and equities [abstract]	
Other Current Liabilities	OTHER CURRENT LIABILITIES

($ millions)	2022
Long-term compensation liability	49.1
Lease liability	24.9
Decommissioning liability	41.6
Other current liabilities	115.6

Long-term Debt	12 Months Ended Dec. 31, 2022

Financial Instruments [Abstract]

Long-term Debt

LONG-TERM DEBT

($ millions)	2022
Bank debt	—
Senior guaranteed notes	1,441.5
Long-term debt	1,441.5
Long-term debt due within one year	538.7
Long-term debt due beyond one year	902.8

Bank debt

The Company has combined facilities of $2.36 billion, including a $2.26 billion syndicated unsecured credit facility with eleven banks and a $100.0 credit facility with one Canadian chartered bank. The current maturity dates of the facilities is November 26, 2026. Both of these facilities constitute and are extendible annually.

The credit facilities and senior guaranteed notes have covenants which restrict the Company's ratio of senior debt to adjusted EBITDA to a maximu total debt to adjusted EBITDA to a maximum of 4.0:1.0 and the ratio of senior debt to capital, adjusted for certain non-cash items as noted above, t The Company was in compliance with all debt covenants at December 31, 2022.

The Company had letters of credit in the amount of $1.8 million outstanding at December 31, 2022 (December 31, 2021 - $1.0 million).

Senior guaranteed notes

At December 31, 2022, the Company has senior guaranteed notes of US$921.0 million and Cdn$195.0 million outstanding. The notes are unsecur the Company's bank credit facilities and carry a bullet repayment on maturity. The senior guaranteed notes have financial covenants similar to thos facilities described above. The Company's senior guaranteed notes are detailed below:

Principal ($ millions)	Coupon Rate	Hedged Equivalent (1) (Cdn$ millions)	Interest Payment Dates	Maturity Date	Financial statem 2022
Cdn$25.0	4.76 %	—	November 22 and May 22	May 22, 2022	—
US$200.0	4.00 %	—	November 22 and May 22	May 22, 2022	—
US$61.5	4.12 %	80.3	October 11 and April 11	April 11, 2023	83.2
Cdn$80.0	3.58 %	80.0	October 11 and April 11	April 11, 2023	80.0
Cdn$10.0	4.11 %	10.0	December 12 and June 12	June 12, 2023	10.0
US$270.0	3.78 %	274.7	December 12 and June 12	June 12, 2023	365.5
Cdn$40.0	3.85 %	40.0	December 20 and June 20	June 20, 2024	40.0
US$257.5	3.75 %	276.4	December 20 and June 20	June 20, 2024	348.5
US$82.0	4.30 %	107.0	October 11 and April 11	April 11, 2025	111.0
Cdn$65.0	3.94 %	65.0	October 22 and April 22	April 22, 2025	65.0
US$230.0	4.08 %	291.1	October 22 and April 22	April 22, 2025	311.3
US$20.0	4.18 %	25.3	October 22 and April 22	April 22, 2027	27.0
Senior guaranteed notes		1,249.8			1,441.5
Due within one year		445.0			538.7
Due beyond one year		804.8			902.8

(1) Includes underlying derivatives which fix the Company's foreign exchange exposure on its US dollar senior guaranteed notes.

Concurrent with the issuance of US$921.0 million senior guaranteed notes, the Company entered into cross currency swa the Company's foreign exchange risk. The CCS fix the US dollar amount of the individual tranches of notes for purposes principal repayments at a notional amount of $1.05 billion. See Note 25 - “Financial Instruments and Derivatives” for ad

Leases	12 Months Ended Dec. 31, 2022
Disclosure of leases [Abstract]	
Leases	

LEASES

Right-of-use asset

($ millions)	Office [(1)]	Fleet Vehicles	Equip
Right-of-use asset at cost	121.9	28.5	
Accumulated depreciation	(55.4)	(20.4)	
Net carrying amount	66.5	8.1	
Reconciliation of movements during the year			
Cost, beginning of year	121.6	25.2	
Accumulated depreciation, beginning of year	(44.3)	(16.1)	
Net carrying amount, beginning of year	77.3	9.1	
Net carrying amount, beginning of year	77.3	9.1	
Additions	—	3.2	
Depreciation	(10.8)	(4.2)	
Lease modification	—	—	
Net carrying amount, end of year	66.5	8.1	

(1) A portion of the Company's office space is subleased. During the year ended December 31, 2022, the Company recorded sublease income of $3.6 million (year ended December 31, 2 of other income.

Lease liability

($ millions)	2022
Lease liability, beginning of year	**141.4**
Additions	**3.8**
Financing	**5.7**
Payments on lease liability	**(26.1)**
Other	**(0.7)**
Lease liability, end of year	**124.1**
Expected to be incurred within one year	**24.9**
Expected to be incurred beyond one year	**99.2**

Some leases contain variable payments that are not included within the lease liability as the payments are based on amounts determined by the les dependent on an index or rate. For the year ended December 31, 2022, variable lease payments of $1.5 million were included in general and admi to property tax payments on office leases (year ended December 31, 2021 - $1.5 million).

During the year ended December 31, 2022, the Company recorded $0.8 million in payments related to short-term leases and leases for low dollar v operating and general and administrative expenses (year ended December 31, 2021 - $0.6 million).

The undiscounted cash flows relating to the lease liability are as follows:

($ millions)
1 year
2 to 3 years
4 to 5 years
More than 5 years
Total [(1)]

(1) Includes both the principal and amounts representing interest.

Other Long-term Liabilities	12 Months Ended Dec. 31, 2022
Subclassifications of assets, liabilities and equities [abstract]	
Other Long-term Liabilities	OTHER LONG-TERM LIABILITIESAt December 31, 2022, the Company had a long-term compensation liability of $40.8 million (December 31, 2021 - $35.8 million) related to share-based compensation. See Note 23 - "Share-based Compensation" for additional information.

Decommissioning Liability	12 Months Ended Dec. 31, 2022
Other Provisions, Contingent Liabilities And Contingent Assets [Abstract]	
Decommissioning Liability	DECOMMISSIONING LIABILITY

($ millions)	2022
Decommissioning liability, beginning of year	**918.8**
Liabilities incurred	**21.6**
Liabilities acquired through capital acquisitions	**3.4**
Liabilities disposed through capital dispositions	**(46.7)**
Liabilities settled [(1)]	**(43.1)**
Revaluation of acquired decommissioning liabilities [(2)]	**3.8**
Change in estimates	**(11.4)**
Change in discount and inflation rate estimates	**(163.0)**
Accretion	**19.2**
Reclassified as liabilities associated with assets held for sale	**(28.4)**
Foreign exchange	**1.3**
Decommissioning liability, end of year	**675.5**
Expected to be incurred within one year	**41.6**
Expected to be incurred beyond one year	**633.9**

(1) Includes $23.0 million received from government grant programs during the year ended December 31, 2022 (year ended December 31, 2021 - $28.7 million).

(2) These amounts relate to the revaluation of acquired decommissioning liabilities at the end of the period using a risk-free discount rate. At the date of acquisition, acquired decommissi

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. The total future de was estimated by management based on the Company's net ownership in all wells and facilities. This includes all estimated costs to reclaim and a facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of its total decom $675.5 million at December 31, 2022 (December 31, 2021 - $918.8 million) based on total estimated undiscounted and uninflated cash flows to set $894.9 million (December 31, 2021 - $896.6 million). These obligations are expected to be settled through 2072, with the majority expected after 2 flows have been discounted using a risk-free rate of 3.28 percent and a derived inflation rate of 2.09 percent (December 31, 2021 - risk-free rate of rate of 1.82 percent).

Shareholders' Capital

12 Months Ended Dec. 31, 2022

Disclosure of classes of share capital [abstract]

Shareholders' Capital

SHAREHOLDERS' CAPITAL

Crescent Point has an unlimited number of common shares authorized for issuance.

	2022		
	Number of shares	**Amount ($ millions)**	Numb s
Common shares, beginning of year	**579,484,032**	**16,963.4**	530,035
Issued on capital acquisitions	**—**	**—**	50,000
Issued on redemption of restricted shares	**1,713,730**	**5.2**	2,109
Issued on exercise of stock options	**1,038,321**	**1.4**	155
Common shares repurchased for cancellation	**(31,347,100)**	**(294.2)**	(2,817
Common shares, end of year	**550,888,983**	**16,675.8**	579,484
Cumulative share issue costs, net of tax	**—**	**(256.5)**	
Total shareholders' capital, end of year	**550,888,983**	**16,419.3**	579,484

Normal Course Issuer Bid ("NCIB")

On March 4, 2022, the Company announced the approval by the Toronto Stock Exchange of its notice to implement a NCIB. The NCIB allows the C cancellation, up to 57,309,975 common shares, or 10 percent of the Company's public float, as at February 28, 2022. The NCIB commenced on M expire on March 8, 2023.

During the year ended December 31, 2022, the Company purchased 31.3 million common shares for total consideration of $294.2 million. The tota commissions and fees, was recognized directly as a reduction in shareholders' equity. Under the NCIB, all common shares purchased are cancelle

Deficit	12 Months Ended Dec. 31, 2022
Equity [abstract]	
Deficit	DEFICIT

($ millions)	2022
Accumulated earnings (deficit)	**(2,700.6)**
Accumulated gain on shares issued pursuant to DRIP [(1)] and SDP [(2)]	**8.4**
Accumulated tax effect on redemption of restricted shares	**15.8**
Accumulated dividends	**(7,886.9)**
Deficit	**(10,563.3)**

(1) Premium Dividend TM and Dividend Reinvestment Plan – suspended in 2015.

(2) Share Dividend Plan – suspended in 2015.

Capital Management

Capital Management	12 Months Ended Dec. 31, 2022
Capital Management [Abstract]	
Capital Management	

CAPITAL MANAGEMENT

($ millions)	2022
Long-term debt [(1)]	1,441.5
Adjusted working capital (surplus) deficiency [(2)]	(95.1)
Unrealized foreign exchange on translation of US dollar long-term debt	(191.7)
Net debt	1,154.7
Shareholders' equity	6,493.4
Total capitalization	7,648.1

(1) Includes current portion of long-term debt.

(2) Adjusted working capital (surplus) deficiency is calculated as accounts payable and accrued liabilities, dividends payable and long-term compensation liability net of equity deriva receivable and prepaids and deposits, including deposit on acquisition.

The following table reconciles cash flow from operating activities to adjusted funds flow from operations for the year ended December 31, 2022 and

($ millions)	2022
Cash flow from operating activities	2,192.2
Changes in non-cash working capital	15.0
Transaction costs	5.1
Decommissioning expenditures	20.1
Adjusted funds flow from operations	2,232.4

Crescent Point's objective for managing its capital structure is to maintain a strong balance sheet and capital base to provide financial flexibility, po future development projects and provide returns to shareholders.

Crescent Point manages its capital structure and short-term financing requirements using a measure not defined in IFRS, or standardized, the ratio funds flow from operations. Net debt to adjusted funds flow from operations is used to measure the Company's overall debt position and to measur Company's balance sheet and might not be comparable to similar financial measures disclosed by other issuers. Crescent Point's objective is to m well positioned to execute its business objectives during periods of volatile commodity prices. Crescent Point monitors this ratio and uses this as a allocation decisions including capital spending levels, returns to shareholders including dividends and share repurchases, and financing considerat debt to adjusted funds flow from operations ratio for the trailing four quarters at December 31, 2022 was 0.5 times (December 31, 2021 - 1.4 times

Crescent Point is subject to certain financial covenants on its credit facilities and senior guaranteed notes agreements and was in compliance with at December 31, 2022. See Note 11 - "Long-term Debt" for additional information regarding the Company's financial covenant requirements.

Crescent Point retains financial flexibility with significant liquidity on its credit facilities. The Company continuously monitors the commodity price er its counterparty exposure to mitigate credit losses and protect its balance sheet.

Commodity Derivative Losses	12 Months Ended Dec. 31, 2022
Analysis of income and expense [abstract]	
Commodity Derivative Losses	COMMODITY DERIVATIVE LOSSES

($ millions)	2
Realized losses	(64
Unrealized gains (losses)	16
Commodity derivative losses	(47

Other Income (Loss)	12 Months Ended Dec. 31, 2022
Analysis of income and expense [abstract]	
Other Income (Loss)	OTHER INCOME

($ millions)	20
Unrealized gain on long-term investments	
Realized gain on sale of long-term investments	
Gain on capital dispositions	25
Government grant for decommissioning expenditures	23
Sublease income	[illegible]
Other	[illegible]
Other income	58

Interest Expense	12 Months Ended Dec. 31, 2022
Analysis of income and expense [abstract]	
Interest Expense	INTERFST EXPENSE

INTEREST EXPENSE

($ millions)	2
Interest expense on long-term debt	6
Unrealized (gain) loss on interest derivative contracts	(
Interest expense	6

Foreign Exchange Gain (Loss)		12 Months Ended Dec. 31, 2022
Foreign exchange rates [abstract]		
Foreign Exchange Gain (Loss)	FOREIGN EXCHANGE GAIN (LOSS)	

($ millions)	2
Realized gain on CCS - principal	6
Translation of US dollar long-term debt	(9
Unrealized gain (loss) on CCS - principal and foreign exchange swaps	
Other	
Foreign exchange gain (loss)	(1

Income Taxes

12 Months Ended Dec. 31, 2022

Income Taxes [Abstract]

Income Taxes

INCOME TAXES

The provision for income taxes is as follows:

($ millions)	2
Current tax:	
Canada	
United States	
Current tax expense	
Deferred tax expense (recovery):	
Canada	41
United States	(2
Deferred tax expense	38
Income tax expense	38

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions, except percentages)	20
Net income before tax	1,871.3
Statutory income tax rate	24.82
Expected provision for income taxes	464.5
Change in corporate tax rates and tax rate variance	1.6
Tax rates in foreign jurisdictions	2.1
Restricted share bonus plan	0.6
Recognition of deferred tax assets	(83.2)
Derecognition of deferred tax assets	—
Non-taxable capital gains	(0.2)
Non-deductible disposition of goodwill	1.9
Other	0.6
Income tax expense	387.9

The composition of the net deferred income tax asset is as follows:

($ millions)	2
Deferred income tax assets	27
Deferred income tax liabilities	(7
Net deferred income tax asset	20

The net deferred income tax assets (liabilities) are expected to be settled in the following periods:

($ millions)	2
Deferred income tax:	
To be settled within one year	1
To be settled beyond one year	18
Deferred income tax	20

The movement in deferred income tax assets (liabilities) are as follows:

($ millions)	At January 1, 2022	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings
Deferred income tax assets:			
Property, plant and equipment	—	—	—
Decommissioning liability	229.6	—	(62.2)
Income tax losses carried forward	814.2	—	(69.6)
Risk management contracts	41.1	—	(39.0)
Lease liabilities	35.3	—	(4.6)
Other	19.5	19.3	(8.9)
	1,139.7	19.3	(184.3)
Deferred income tax liabilities:			
Property, plant and equipment	(533.4)	—	(209.7)
Risk management contracts	(13.4)	—	2.6
ROU asset	(22.8)	—	3.5
	(569.6)	—	(203.6)
Net deferred income tax assets (liabilities)	570.1	19.3	(387.9)

($ millions)	At January 1, 2021	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings
Deferred income tax assets:			
Property, plant and equipment	248.9	—	(248.9)
Decommissioning liability	262.2	—	(32.6)
Income tax losses carried forward	833.1	—	(18.9)
Risk management contracts	11.6	—	29.5
Lease liabilities	40.1	—	(4.8)
Other	8.5	1.9	9.1
	1,404.4	1.9	(266.6)
Deferred income tax liabilities:			
Property, plant and equipment	—	—	(533.4)
Risk management contracts	(9.9)	—	(3.5)
ROU asset	(26.6)	—	3.8
	(36.5)	—	(533.1)
Net deferred income tax assets (liabilities)	1,367.9	1.9	(799.7)

The approximate amounts of tax pools available as at December 31, 2022 and 2021 are as follows:

($ millions)	**2**
Tax pools:	
Canada	**5,68**
United States	**3,02**
Total	**8,71**

Deferred tax assets are recognized to the extent of expected utilization of tax attributes, based on estimated undiscounted future cash flows include independent reserve report.

The above tax pools include estimated Canadian non-capital losses carried forward of $1.36 billion (December 31, 2021 - $1.99 billion) that expire 2040, and U.S. net operating losses of $2.30 billion (December 31, 2021 - $2.22 billion) of which $1.55 billion will expire in the years 2033 through $744.9 million will not expire. A deferred income tax asset has not been recognized for U.S. net operating losses of $507.2 million (December 31, 2 other Canadian tax pools of $69.0 million (December 31, 2021 - $69.0 million) as there is not sufficient certainty regarding future utilization.

At December 31, 2022, a deferred tax asset has not been recognized in respect of temporary differences associated with investments in subsidiari temporary differences will reverse in the foreseeable future. The deductible temporary differences associated with investments in subsidiaries is ap (December 31, 2021 - $1.72 billion).

The Company received notices of reassessment from the Canada Revenue Agency in 2014 and 2015 disallowing $149.3 million of tax pools and $ tax credits relating to an acquired entity. The Company has filed notices of objections, however, the benefit of these tax pools and investment tax c

the year ended December 31, 2021 due to the uncertainty of being successful in defending its position. A $37.5 million deferred income tax expens
year ended December 31, 2021 as a result of removing the tax pools.

Share-based Compensation

12 Months Ended Dec. 31, 2022

Share-based Payment Arrangements [Abstract]

Share-based Compensation

SHARE-BASED COMPENSATION

The following table reconciles the number of restricted shares, ESVP awards, PSUs and DSUs for the year ended December 31, 2022:

	Restricted Shares	ESVP	PSUs [(1)]
Balance, beginning of year	3,267,717	8,329,291	3,214,620
Granted	710,819	1,288,598	904,469
Redeemed	(1,718,906)	(3,691,820)	(1,405,913)
Forfeited	(14,892)	(651,591)	—
Balance, end of year	2,244,738	5,274,478	2,713,176

(1) Based on underlying units before any effect of performance multipliers.

The following table reconciles the number of restricted shares, ESVP awards, PSUs and DSUs for the year ended December 31, 2021:

	Restricted Shares	ESVP	PSUs [(1)]
Balance, beginning of year	4,704,129	10,449,383	3,789,689
Granted	1,230,133	2,570,746	2,053,574
Redeemed	(2,146,716)	(3,417,496)	(2,221,058)
Forfeited	(519,829)	(1,273,342)	(407,585)
Balance, end of year	3,267,717	8,329,291	3,214,620

(1) Based on underlying units before any effect of performance multipliers.

The following table provides summary information regarding stock options outstanding as at December 31, 2022:

	Stock Options (number of units)	Weight
Balance, beginning of year	5,839,464	
Exercised	(1,446,571)	
Forfeited	(398,610)	
Expired	(105,153)	
Balance, end of year	3,889,130	

The following table summarizes information regarding stock options outstanding as at December 31, 2022:

Range of exercise prices ($)	Number of stock options outstanding	Weighted average remaining term for options outstanding (years)	Weighted average exercise price per share for options outstanding ($)	Number of stock options exercisable
1.09 - 1.65	1,884,156	4.25	1.09	307,638
1.66 - 5.16	470,946	3.26	3.92	137,543
5.17 - 9.86	505,809	4.77	5.91	113,490
9.87 - 10.06	1,028,219	2.02	10.06	1,028,219
	3,889,130	3.61	4.43	1,586,890

The following table provides summary information regarding stock options outstanding as at December 31, 2021:

	Stock Options (number of units)	Weight
Balance, beginning of year	5,940,871	
Granted	534,264	
Exercised	(261,486)	
Forfeited	(285,047)	
Expired	(89,138)	
Balance, end of year	5,839,464	

The volume weighted average trading price of the Company's common shares was $9.52 per share during the year ended December 31, 2022 (yea
2021 - $5.14 per share).

For the year ended December 31, 2022, the Company calculated total share-based compensation of $77.3 million (year ended December 31, 2021
estimated forfeitures, of which $14.7 million was capitalized (year ended December 31, 2021 - $14.3 million).

At December 31, 2022, the current portion of long-term compensation liability of $49.1 million was included in other current liabilities (December 31
$40.8 million was included in other long-term liabilities (December 31, 2021 - $35.8 million).

Per Share Amounts	12 Months Ended Dec. 31, 2022
Earnings per share [abstract]	
Per Share Amounts	PER SHARE AMOUNTS The following table summarizes the weighted average shares used in calculating net income per share:

	2022
Weighted average shares – basic	566,710,644
Dilutive impact of share-based compensation	4,357,422
Weighted average shares – diluted	571,068,066

Financial Instruments and Derivatives	12 Months Ended Dec. 31, 2022
Financial Instruments [Abstract]	
Financial Instruments and Derivatives	

FINANCIAL INSTRUMENTS AND DERIVATIVES

The Company's financial assets and liabilities are comprised of cash, accounts receivable, derivative assets and liabilities, accounts payable and a payable and long-term debt.

Crescent Point's derivative assets and liabilities are transacted in active markets. The Company classifies the fair value of these transactions accor value hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 - Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 - Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substa corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.
- Level 3 - Values are based on prices or valuation techniques that are not based on observable market data.

Accordingly, Crescent Point's derivative assets and liabilities are classified as Level 2. Assessment of the significance of a particular input to the fai requires judgment and may affect the placement within the fair value hierarchy.

Discussions of the fair values and risks associated with financial assets and liabilities, as well as summarized information related to derivative posit

a) Carrying amount and fair value of financial instruments

The fair value of cash, accounts receivable, accounts payable and accrued liabilities and dividends payable approximate their carrying amount due those instruments. The fair value of the amounts drawn on bank credit facilities is equal to its carrying amount as the facilities bear interest at floatin that are indicative of market rates. These financial instruments are classified as financial assets and liabilities at amortized cost and are reported at

Crescent Point's derivative assets and liabilities are transacted in active markets, classified as financial assets and liabilities at fair value through pr at each period with the resulting gain or loss recorded in net income.

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair va 2022:

($ millions)	2022 Carrying Value	2022 Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant othe observable inpu (Level
Financial assets				
Derivatives	235.3	235.3	—	235.
	235.3	235.3	—	235.
Financial liabilities				
Derivatives	8.7	8.7	—	8.
Senior guaranteed notes (1)	1,441.5	1,372.9	—	1,372.
	1,450.2	1,381.6	—	1,381.

(1) The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair va 2021:

($ millions)	2021 Carrying Value	2021 Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant othe observable inpu (Level
Financial assets				
Derivatives	220.5	220.5	—	220.
	220.5	220.5	—	220.
Financial liabilities				
Derivatives	164.9	164.9	—	164.
Senior guaranteed notes (1)	1,638.8	1,618.4	—	1,618.
	1,803.7	1,783.3	—	1,783.

(1) The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian
rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

Derivative assets and liabilities

Derivative assets and liabilities arise from the use of derivative contracts. Crescent Point's derivative assets and liabilities are classified as Level 2 inputs including quoted forward prices for commodities, time value and volatility factors. Accordingly, the Company's derivative financial instrument through profit or loss and are reported at fair value with changes in fair value recorded in net income.

The following table summarizes the fair value as at December 31, 2022 and the change in fair value for the year ended December 31, 2022:

($ millions)	Commodity (1)	Interest (2)	Foreign exchange (3)
Derivative assets (liabilities), beginning of year	(154.4)	5.6	170.6
Unrealized change in fair value	168.4	1.1	4.4
Derivative assets, end of year	14.0	6.7	175.0
Derivative assets, end of year	22.6	6.7	175.1
Derivative liabilities, end of year	(8.6)	—	(0.1)

(1) Includes crude oil, crude oil differentials, propane, natural gas and natural gas differential contracts.

(2) Interest payments on CCS.

(3) Includes principal portion of CCS and foreign exchange contracts.

The following table summarizes the fair value as at December 31, 2021 and the change in fair value for the year ended December 31, 2021:

($ millions)	Commodity (1)	Interest (2)	Foreign exchange (3)
Derivative assets (liabilities), beginning of year	(26.3)	7.3	205.0
Unrealized change in fair value	(128.1)	(1.7)	(34.4)
Derivative assets (liabilities), end of year	(154.4)	5.6	170.6
Derivative assets, end of year	5.4	5.7	175.6
Derivative liabilities, end of year	(159.8)	(0.1)	(5.0)

(1) Includes crude oil, crude oil differentials, propane, natural gas and natural gas differential contracts.

(2) Interest payments on CCS and interest derivative contracts.

(3) Includes principal portion of CCS and foreign exchange contracts.

Offsetting financial assets and liabilities

Financial assets and liabilities are only offset if the Company has the legal right to offset and intends to settle on a net basis or settle the asset and Company offsets derivative assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. The following gross asset and liability positions of the Company's financial derivatives by contract that are offset on the balance sheet as at December 31, 2022

			2022		
($ millions)	Asset	Liability	Net	Asset	Li
Gross amount	246.3	(19.7)	226.6	218.9	(1
Amount offset	(11.0)	11.0	—	1.6	
Net amount	235.3	(8.7)	226.6	220.5	(1

b) Risks associated with financial assets and liabilities

The Company is exposed to financial risks from its financial assets and liabilities. The financial risks include market risk relating to commodity price exchange rates and equity price as well as credit and liquidity risk.

Commodity price risk

The Company is exposed to commodity price risk on crude oil and condensate, NGLs and natural gas revenues. To manage a portion of this risk, t into various derivative agreements.

The following table summarizes the unrealized gains (losses) on the Company's commodity financial derivative contracts and the resulting impact fluctuations in commodity prices or differentials, with all other variables held constant:

		Impact on Income Before Tax		
($ millions)		Year ended December 31, 2022		Ye
		Increase 10%	Decrease 10%	Increase 1
Commodity price				
Crude oil and condensate		(40.3)	38.8	(14
Natural gas		(3.1)	3.2	(
Differential				
Natural gas		2.6	(2.6)	

Interest rate risk

The Company is exposed to interest rate risk on amounts drawn on its bank credit facilities to the extent of changes in market interest rates. At Dec
Company was undrawn on its credit facilities and had no floating rate debt outstanding.

Foreign exchange risk

The Company is exposed to foreign exchange risk in relation to its US dollar denominated long-term debt, investment in U.S. subsidiaries and on a
sales. Crescent Point utilizes foreign exchange derivatives to hedge its foreign exchange exposure on its US dollar denominated long-term debt. To
risk relating to crude oil sales, the Company utilizes a combination of foreign exchange swaps and fixed price WTI crude oil contracts that settle in

The following table summarizes the resulting unrealized gains (losses) impacting income before tax due to the respective changes in the period en
exchange rates, with all other variables held constant:

		Impact on Income Before Tax		
($ millions)	Exchange Rate	Year ended December 31, 2022		Ye
Cdn$ relative to US$		Increase 10%	Decrease 10%	Increase 1
US dollar long-term debt	Period End	124.6	(124.6)	16
Cross currency swaps	Forward	(123.7)	123.7	(16
Foreign exchange swaps	Forward	4.3	(4.3)	(

Equity price risk

The Company is exposed to equity price risk on its own share price in relation to certain share-based compensation plans detailed in Note 23 - "Sh
The Company has entered into total return swaps to mitigate its exposure to fluctuations in its share price by fixing the future settlement cost on a p
plans.

The following table summarizes the unrealized gains (losses) on the Company's equity derivative contracts and the resulting impact on income bef
respective changes in the applicable share price, with all other variables held constant:

	Impact on Income Before Tax		
($ millions)	Year ended December 31, 2022		Ye
Share price	Increase 50%	Decrease 50%	Increase 5
Total return swaps	26.8	(26.8)	2

Credit risk

The Company is exposed to credit risk in relation to its physical oil and gas sales, financial counterparty and joint venture receivables. A substantia
accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. To mitigate credit risk associated
portfolio, Crescent Point obtains financial assurances such as parental guarantees, letters of credit, prepayments and third party credit insurance. I
approximately 98 percent of the Company's oil and gas sales are with entities considered investment grade.

At December 31, 2022, approximately 4 percent (December 31, 2021 - 3 percent) of the Company's accounts receivable balance was outstanding
the Company's average expected credit loss was 0.93 percent (December 31, 2021 - 0.92 percent) on a portion of the Company's accounts receiva
joint venture receivables.

Liquidity risk

The Company manages its liquidity risk through managing its capital structure and continuously monitoring forecast cash flows and available credit
facilities as well as other potential sources of capital.

At December 31, 2022, the Company had available unused borrowing capacity on bank credit facilities of approximately $2.36 billion as well as cas

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2022, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5
Accounts payable and accrued liabilities	448.2	—	—	
Dividends payable	99.4	—	—	
Derivative liabilities (1)	12.6	—	—	
Senior guaranteed notes (2)	486.6	816.2	26.9	

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS related to the senior guaranteed notes, which fix the amounts due in Canadian dollars.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2021, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5
Accounts payable and accrued liabilities	450.7	—	—	
Dividends payable	43.5	—	—	
Derivative liabilities (1)	249.0	1.1	0.3	
Senior guaranteed notes (2)	280.3	829.2	474.6	
Bank credit facilities (3)	11.7	23.5	346.3	

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS and foreign exchange swap related to the senior guaranteed notes, which fix the amounts due

(3) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2021 and includes undiscounted cash outflows pursuant to the CCS related

c) Derivative contracts

The following is a summary of the derivative contracts in place as at December 31, 2022:

Financial WTI Crude Oil Derivative Contracts – Canadian Dollar (1)							
	Swap		Collar			Three-way Co	
Term	Volume (bbls/d)	Average Price ($/bbl)	Volumes (bbls/d)	Average Sold Call Price ($/bbl)	Average Bought Put Price ($/bbl)	Volume (bbls/d)	Average Sold Call Price ($/bbl)
2023	1,356	90.04	10,586	114.99	101.39	616	118.11

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial AECO Natural Gas Derivative Contracts – Canadian Dollar (1)				
	Swap		Collar	
Term	Volume (GJ/d)	Average Price ($/GJ)	Volume (GJ/d)	Average Sold Call Price ($/GJ)
2023	21,605	4.68	7,397	10.21
2024 January - March	10,000	5.13	—	—

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial NYMEX Natural Gas Differential Derivative Contracts – US Dollar (1)			
Term	Volume (mmbtu/d)	Contract	Basis
January 2023 - March 2025	17,500	Basis Swap	AECO

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial Cross Currency Derivative Contracts				
		Receive Notional Principal		Pay Notional Principal
Term	Contract	(US$ millions)	Fixed Rate (US%)	(Cdn$ millions)
January 2023 - April 2023	Swap	61.5	4.12	80.3
January 2023 - June 2023	Swap	270.0	3.78	274.7
January 2023 - June 2024	Swap	257.5	3.75	276.4
January 2023 - April 2025	Swap	82.0	4.30	107.0
January 2023 - April 2025	Swap	230.0	4.08	291.1
January 2023 - April 2027	Swap	20.0	4.18	25.3

Financial Foreign Exchange Forward Derivative Contracts				
			Receive Notional Principal	
Settlement Date	Contract	Receive Currency	($ millions)	Curre
January 2023	Swap	US$	15.0	C
January 2023	Swap (1)	Cdn$	63.9	U

(1) Based on an average floating exchange rate.

Financial Equity Derivative Contracts		
		Notional Principal
Term	Contract	($ millions)
January 2023 - April 2023	Swap	11.9
January 2023 - April 2024	Swap	7.2
January 2023 - April 2025	Swap	3.6

Related Party Transactions	12 Months Ended Dec. 31, 2022
Related party transactions [abstract]	
Related Party Transactions	RELATED PARTY TRANSACTIONS **Compensation of key management personnel** Key management personnel of the Company include its directors and executive officers. In 2022, the Company recorded $6.1 million (2021 - $6.1 million) relating to compensation of key management personnel and nil (2021 - $2.8 million) for severance relating to key management personnel. In 2022, share-based compensation costs relating to compensation of key management personnel and severance were $24.2 million (2021 - $23.4 million) and nil (2021 - $1.8 million), respectively.

Commitments	12 Months Ended Dec. 31, 2022
Capital commitments [abstract]	
Commitments	COMMITMENTS

COMMITMENTS

At December 31, 2022, the Company had contractual obligations and commitments as follows:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 yea
Operating (1)	11.7	15.7	9.8	11
Gas processing	64.6	105.4	88.5	291
Transportation	43.3	74.8	41.5	40
Capital	7.3	—	—	-
Total contractual commitments (2)	126.9	195.9	139.8	343

(1) Includes operating costs on the Company's office space, net of $18.1 million recoveries from subleases.

(2) Excludes contracts accounted for under IFRS 16. See Note 12 - "Leases" for additional information.

Significant Subsidiaries	12 Months Ended Dec. 31, 2022
Disclosure of subsidiaries [abstract]	
Significant Subsidiaries	SIGNIFICANT SUBSIDIARIES The Company has the following significant subsidiaries, each owned 100% directly and indirectly, at December 31, 2022:

Subsidiary Name
Crescent Point Resources Partnership
Crescent Point Holdings Ltd.
Crescent Point Energy U.S. Corp.
Crescent Point U.S. Holdings Corp.

Supplemental Disclosures | **12 Months Ended Dec. 31, 2022**

[Supplemental Disclosures [Abstract]]

Supplemental Disclosures

SUPPLEMENTAL DISCLOSURES

Comprehensive income statement presentation

The Company’s statements of comprehensive income are prepared primarily by nature of expense, with the exception of compensation expenses v
operating, general and administrative and share-based compensation line items, as follows:

($ millions)	2
Operating	6
General and administrative	6
Share-based compensation	3
Total compensation expenses	15

Cash flow statement presentation

($ millions)	2
Operating activities	
Changes in non-cash working capital:	
Accounts receivable	(1
Prepaids and deposits	(1
Accounts payable and accrued liabilities	(
Other current liabilities	
Other long-term liabilities	
	(1
Investing activities	
Changes in non-cash working capital:	
Accounts receivable	
Other long-term receivable	
Accounts payable and accrued liabilities	(
	(
Financing activities	
Changes in non-cash working capital:	
Prepaids and deposits	(4
Accounts payable and accrued liabilities	
Dividends payable	5
	1

Supplementary financing cash flow information

The Company's reconciliation of cash flow from financing activities is outlined in the table below:

($ millions)	**Dividends payable**	**Long-term debt [1**
December 31, 2020	1.3	2,259.6
Changes from cash flow from financing activities:		
Decrease in bank debt, net		(34.6
Repayment of senior guaranteed notes		(217.6
Dividends paid	(5.6)	
Payments on principal portion of lease liability		
Non-cash changes:		
Dividends declared	47.8	
Additions		
Other		
Foreign exchange		(37.2
December 31, 2021	43.5	1,970.2
Changes from cash flow from financing activities:		
Decrease in bank debt, net		**(338.5**
Repayment of senior guaranteed notes		**(281.8**
Realized gain on cross currency swap maturity		**63.8**
Dividends paid	**(144.7)**	
Payments on principal portion of lease liability		
Non-cash changes:		
Dividends declared	**200.6**	
Additions		
Other		
Foreign exchange		**27.8**
December 31, 2022	**99.4**	**1,441.5**

(1) Includes current portion of long-term debt.

(2) Includes current portion of lease liability.

Geographical Disclosure	12 Months Ended Dec. 31, 2022
Disclosure of geographical areas [abstract]	
Geographical Disclosure	GEOGRAPHICAL DISCLOSURE

GEOGRAPHICAL DISCLOSURE

The following table reconciles oil and gas sales by country:

($ millions) [1]	2
Canada	
Crude oil and condensate sales	**3,31**
NGL sales	**22**
Natural gas sales	**30**
Total Canada	**3,84**
U.S.	
Crude oil and condensate sales	**55**
NGL sales	**5**
Natural gas sales	**3**
Total U.S.	**64**
Total oil and gas sales	**4,49**

(1) Oil and gas sales are reported before realized derivatives.

The following table reconciles non-current assets by country:

($ millions)	2022
Canada	**6,977.9**
U.S.	**1,519.3**
Total	**8,497.2**

Subsequent Events	12 Months Ended Dec. 31, 2022
Disclosure of non-adjusting events after reporting period [abstract]	
Subsequent Events	SUBSEQUENT EVENTS *Acquisition of Kaybob Duvernay Assets* On January 11, 2023, Crescent Point completed the acquisition of certain Kaybob Duvernay assets in Alberta for cash consideration of $370.6 million, including closing adjustments, which is expected to be allocated substantially to PP&E and E&E. Cash consideration was funded primarily through cash on hand and included a deposit on acquisition of $18.7 million.

Significant Accounting Policies (Policies)	12 Months Ended Dec. 31, 2022
Corporate Information And Statement of IFRS Compliance [Abstract]	
Preparation	Preparation These consolidated financial statements are presented under International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of March 1, 2023, the date the Board of Directors approved the statements. The Company's presentation currency is Canadian dollars and all amounts reported are Canadian dollars unless noted otherwise. References to "US$" and "US dollars" are to United States ("U.S.") dollars. Crescent Point's Canadian and U.S. operations are aggregated into one reportable segment based on similar economic characteristics and the similar nature of the assets, products, production processes and customers.
Basis of measurement, functional and presentation currency	Basis of measurement, functional and presentation currencyThe Company's presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period end exchange rates for assets and liabilities and at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income as cumulative translation adjustments.
Use of estimate and judgments	Use of estimates and judgments The preparation of consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected. The Company also faces uncertainties related to future environmental laws and climate-related regulations, which could affect the Company's financial position and future earnings. This transition to a lower-carbon society, as well as the physical impacts of climate change, could result in increased operating costs and reduced demand for oil and gas products. As a result, this could change a number of variables and assumptions used to determine the estimated recoverable amounts of the Company's oil and gas assets. The unpredictable nature, timing and extent of climate-related initiatives presents various risks and uncertainties, including to management's judgements, estimates and assumptions that affect the application of accounting policies. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below. Oil and gas activities Reserves estimates, although not reported as part of the Company's consolidated financial statements, can have a significant effect on net income, assets and liabilities as a result of their impact on depletion, depreciation and amortization ("DD&A"), decommissioning liability,

deferred taxes, asset impairments and impairment reversals, and business combinations. Independent petroleum reservoir engineers perform evaluations of the Company's oil and gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

For purposes of impairment testing, property, plant and equipment ("PP&E") is aggregated into cash-generating units ("CGUs"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructure, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations.

The determination of technical feasibility and commercial viability, based on the presence of reserves and which results in the transfer of assets from exploration and evaluation ("E&E") to PP&E, is subject to judgment.

Decommissioning liability

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are impacted by estimates with respect to the cost and timing of decommissioning.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Fair value measurement

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of derivative instruments include forward benchmark prices, discount rates, share price, forward foreign exchange rates and forward interest rates.

Joint control

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the capital and operating activities of the projects it undertakes with partners and when the decisions in relation to those activities require unanimous consent.

Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax assets and liabilities recognize the extent that temporary differences will be receivable and payable in future periods. The calculation of the asset and liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, expected cash flows from estimated proved plus probable reserves and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

Principles of Consolidation

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries and any reference to the “Company” throughout these consolidated financial statements refers to the Company and its subsidiaries. All transactions between the Company and its subsidiaries have been eliminated.

The Company conducts some of its oil and gas production activities through jointly controlled operations and the financial statements reflect only the Company's proportionate interest in such activities. Joint control exists for contractual arrangements governing the Company's assets whereby the Company has less than 100 percent working interest, all the partners have control of the arrangement collectively, and share the associated risks. The Company does not have any joint arrangements that are material to the Company or that are structured through joint venture arrangements.

Property, Plant and Equipment

Property, Plant and Equipment

Items of PP&E, which primarily consist of oil and gas development and production assets, are measured at cost less accumulated depletion, depreciation and any accumulated impairment losses or impairment reversals. Development and production assets are accumulated into CGUs and account for the cost of developing the commercial reserves and initiating production.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as development and production assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in net income as incurred. Capitalized development and production assets generally represent costs incurred in developing reserves and initiating or enhancing production from such reserves. The carrying amount of any sold component is derecognized.

Depletion and Depreciation

Development and production assets are depleted using the unit-of-production method based on estimated proved plus probable reserves before royalties, as determined by independent petroleum reservoir engineers. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proved plus probable reserves.

Corporate assets are depreciated on a straight line basis over the estimated useful lives of the related assets, ranging from 5 to 16 years.

Impairment

The carrying amounts of PP&E, which takes into account the discounted abandonment and reclamation costs on proved plus probable undeveloped oil and gas reserves, are grouped into CGUs and reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income.

Assets are grouped into CGUs based on the integration between assets, shared infrastructure, the existence of common sales points, geography, geological structure and the manner in which management monitors and makes decisions regarding operations. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent petroleum reservoir engineers. The recoverable amount is the higher of fair value less costs of disposal and the value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate. The fair value less costs of disposal and value in use estimates are categorized as Level 3 according to the IFRS 13 fair value hierarchy.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined, net of depletion, had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net income.

Exploration and Evaluation

Exploration and Evaluation

Exploration and evaluation assets are comprised of the accumulated expenditures incurred in an area where technical feasibility and commercial viability has not yet been determined. Exploration and evaluation assets include undeveloped land and any drilling costs thereon.

Technical feasibility and commercial viability are considered to be determinable when reserves are discovered. Upon determination of reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E.

Costs incurred prior to acquiring the legal rights to explore an area are expensed as incurred.

Amortization

Undeveloped land classified as E&E assets is amortized by major area over the average primary lease term and recognized in net income. Drilling costs classified as E&E assets are not amortized, but are subject to impairment.

Impairment

Exploration and evaluation assets are reviewed quarterly for indicators of impairment and upon reclassification from E&E assets to PP&E. Exploration and evaluation assets are tested for impairment at the operating segment level by combining E&E assets with PP&E. The recoverable amount is the greater of fair value less costs of disposal or value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves, plus the fair market value of undeveloped land. Value-in-use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate.

Impairments of E&E assets are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been, net of amortization, had no impairment been recognized.

Decommissioning Liability	Decommissioning LiabilityThe Company recognizes the present value of a decommissioning liability in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis using the relevant risk free rate, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the underlying proved plus probable reserves. Accretion expense is recognized in net income. Revisions to the discount rate, estimated timing or amount of future cash flows would also result in an increase or decrease to the decommissioning liability and related asset.
Goodwill	GoodwillThe Company records goodwill relating to business combinations when the purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The goodwill balance is assessed for impairment annually or as events occur that could result in impairment. Goodwill is tested for impairment at an operating segment level by combining the carrying amounts of PP&E, E&E assets and goodwill and comparing this to the recoverable amount. Any excess of the carrying amount over the recoverable amount is the impairment amount. The recoverable amount estimates is categorized as Level 3 according to the IFRS 13 fair value hierarchy. Impairment charges, which are not tax affected, are recognized in net income. Goodwill is reported at cost less any accumulated impairment. Goodwill impairments are not reversed.
Share-based Compensation	Share-based Compensation

Restricted shares granted under the Restricted Share Bonus Plan are accounted for at fair value and vest on terms up to three years from the grant date determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and recognized when they occur. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the portion of share-based compensation directly attributable to development activities, with a corresponding decrease to share-based compensation expense. At the time the restricted shares vest, the issuance of shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

Employee Share Value Plan ("ESVP") awards are accounted for at fair value and vest on terms of up to three years from the grant date as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the ESVP awards on the date of grant and subsequently adjusted to reflect the fair value at each period end. The expense is recognized over the service period, with a corresponding increase to long-term compensation liability. ESVP awards are settled in cash upon vesting based on the prevailing Crescent Point share price and the aggregate amount of dividends paid from the grant date.

Performance share units ("PSUs") are accounted for at fair value and vest on terms of up to three years from the grant date as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the PSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Market performance conditions are factored into the fair value and the best estimate of non-market performance conditions is used to determine an estimate of the number of units that will vest. Fair value is based on the expected cash payment per PSU and the expected number of PSUs to vest, calculated from multipliers based on internal and external performance metrics. The expense is recognized over the service period, with a corresponding increase to long-term compensation liability. PSUs are settled in cash upon vesting based on the prevailing Crescent Point share price, the aggregate amount of dividends paid from the grant date and the performance multipliers.

Deferred share units (“DSUs”) are accounted for at fair value. Share-based compensation expense is determined based on the estimated fair value of the DSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Fair value is based on the prevailing Crescent Point share price.

Stock options are accounted for at fair value and have a maximum term of seven years and vest on terms as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the stock options on the date of the grant. Upon vesting, the stock option holder may either exercise their stock options to purchase one common share per option at the exercise price or, at the Company's discretion, surrender their stock options for a cash payment in an amount equal to the aggregate positive difference, if any, between the market price and the exercise price of the number of common shares associated with the stock options surrendered. Alternatively, the stock option holder may also, at the Company's discretion, surrender their stock options for common shares having a value equivalent to the cash payment.

Income taxes

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the estimated effect of any differences between the accounting and tax basis of assets and liabilities, using enacted or substantively enacted income tax rates expected to apply when the deferred tax asset or liability is settled. The effect of a change in income tax rates on deferred income taxes is recognized in net income in the period in which the change occurs.

The tax expense for the period comprises current and deferred tax. Tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity. In this case, the tax is also recognized in other comprehensive income or directly in equity, respectively.

The Company is able to deduct certain settlements under its Restricted Share Bonus Plan. To the extent the tax deduction exceeds the cumulative remuneration cost for a particular restricted share grant recorded in net income, the tax benefit related to the excess is recorded directly within equity.

A deferred tax asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized. Deferred income tax assets and liabilities are presented as non-current.

Financial Instruments

Financial Instruments

The Company uses financial derivative instruments and physical delivery commodity contracts from time to time to reduce its exposure to fluctuations in commodity prices, share price, foreign exchange rates and interest rates. The Company also makes investments in companies from time to time in connection with the Company's acquisition and divestiture activities.

Financial derivative instruments

Financial derivative instruments are included in current assets/liabilities except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets/liabilities.

The Company has not designated any of its financial derivative contracts as effective accounting hedges and, accordingly, fair values its financial derivative contracts with the resulting gains and losses recorded in net income.

The fair value of a financial derivative instrument on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair values are based on quoted market prices where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at the reporting date.

Financial assets and liabilities

Financial assets and liabilities are measured at fair value on initial recognition. For non-equity instruments, measurement in subsequent periods depends on the classification of the financial asset or liability as "fair value through profit or loss" or "amortized cost".

Financial assets and liabilities classified as fair value through profit or loss are subsequently carried at fair value, with changes recognized in net income.

Financial assets and liabilities classified as amortized cost are subsequently carried at amortized cost using the effective interest rate method.

Currently, the Company classifies all non-equity financial instruments which are not financial derivative instruments as amortized cost.

At each reporting date, the Company assesses whether there is objective evidence that a financial asset carried at amortized cost is impaired. If such evidence exists, the Company recognizes an impairment loss in net income. Impairment losses are reversed in subsequent periods if the impairment loss decrease can be related objectively to an event occurring after the impairment was recognized.

For investments in equity instruments, the subsequent measurement is dependent on the Company's election to classify such instruments as fair value through profit or loss or fair value through other comprehensive income. Currently, the Company classifies all investments in equity instruments as fair value through profit or loss, whereby the Company recognizes movements in the fair value of the investment (adjusted for dividends) in net income. If the fair value through other comprehensive income classification is selected, the Company would recognize any dividends from the investment in net income and would recognize fair value re-measurements of the investment in other comprehensive income.

Impairment of financial assets

Impairment losses are recognized using an expected credit loss model. The Company has adopted the simplified expected credit loss model for its accounts receivable, which permits the use of the lifetime expected loss provision.

To measure the expected credit losses, accounts receivable have been grouped based on shared credit risk characteristics and days past due. The Company uses judgment in making these assumptions and selecting the inputs into the expected loss calculation based on past history, existing market conditions and forward looking estimates at the end of each reporting period.

Business Combinations	Business CombinationsBusiness combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The consideration paid of an acquisition is measured as the fair value of the acquired assets by estimating the discounted after-tax future net cash flows, the fair value of equity instruments issued and the fair value of liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in net income. Transaction costs associated with business combinations are expensed as incurred.
Foreign Currency Translation	Foreign Currency Translation

Foreign operations

The Company has operations in the U.S. transacted via U.S. subsidiaries. The assets and liabilities of foreign operations are translated to Canadian dollars at exchange rates in effect at the balance sheet date. The income and expenses of foreign operations are translated to Canadian dollars using average exchange rates for the period. The resulting unrealized gain or loss is included in other comprehensive income.

Foreign transactions

Transactions in foreign currencies not incurred by the Company's U.S. subsidiaries are translated to Canadian dollars at exchange rates in effect at the transaction dates. Foreign currency assets and liabilities are translated to Canadian dollars at exchange rates in effect at the balance sheet date and income and expenses are translated to Canadian dollars using average exchange rates for the period. Both realized and unrealized gains and losses resulting from the settlement or restatement of foreign currency transactions are included in net income.

Revenue Recognition	Revenue Recognition

The Company’s major revenue sources are comprised of sales from the production of crude oil and condensate, natural gas liquids ("NGLs") and natural gas. Revenue is recognized when control of the product transfers to the customer and the collection is reasonably probable, generally upon delivery of the product. Sales of crude oil and condensate, NGLs and natural gas production are based on variable pricing as the transaction prices are based on benchmark commodity prices and other variable factors, including quality differentials and location.

Each contract is evaluated based on the nature of the performance obligations, including the Company’s role as either principal or agent. Where the Company acts as principal, revenue is recognized on a gross basis. Where the Company acts as agent, revenue is recognized on a net basis.

Cash and Cash Equivalents	Cash and Cash EquivalentsCash and cash equivalents include short-term investments with original maturities of three months or less.
Leases	Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the commencement date, the lease liability is recognized at the present value of the future lease payments and discounted using the interest rate implicit in the lease or the Company's incremental borrowing rate. A corresponding right-of-use ("ROU") asset will be recognized at the amount of the lease liability, adjusted for any lease incentives received and initial direct costs incurred. Over the term of the lease, financing expense is recognized on the lease liability using the effective interest rate method and charged to net income, lease payments are applied against the lease liability and depreciation on the ROU asset is recorded by class of underlying asset.

The lease term is the non-cancellable period of a lease and includes periods covered by an optional lease extension option if reasonably certain the Company will exercise the option to extend. Conversely, periods covered by an option to terminate are included if the Company does not expect to end the lease during that time frame. Leases with a term of less than twelve months or leases for underlying low value assets are recognized as an expense in net income on a straight-line basis over the lease term.

A lease modification will be accounted for as a separate lease if it materially changes the scope of the lease. For a modification that is not a separate lease, on the effective date of the lease modification, the Company will remeasure the lease liability and corresponding ROU asset using the interest rate implicit in the lease or the Company's incremental borrowing rate. Any variance between the remeasured ROU asset and lease liability will be recognized as a gain or loss in net income to reflect the change in scope.

The Company also acts as an intermediate lessor for office space sub-leased to other companies. As a lessor, the Company will evaluate whether a lease is a finance or operating lease. Leases where the Company transfers substantially all the risks and rewards of ownership are classified as finance leases. Conversely, leases where the risks and rewards of ownership are retained by the Company are operating leases. The head lease between the Company and the building, and the sub-lease between the Company and tenants, are accounted for separately. The lease classification of the sub-lease is based upon the head lease and not the underlying asset.

Earnings Per Share

Earnings Per Share

Basic earnings per share (“EPS”) is calculated by dividing the net income for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period.

Diluted EPS is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to dilutive instruments, being restricted shares issued under the Company’s Restricted Share Bonus Plan and stock options under the Company's Stock Option Plan, is computed using the treasury stock method. The treasury stock method assumes that the deemed proceeds related to unrecognized share-based compensation are used to repurchase shares at the average market price during the period.

Government Grants

Government GrantsThe Company may receive government grants which provide immediate financial assistance as compensation for costs or expenditures to be incurred. Government grants are accounted for when there is reasonable assurance that conditions attached to the grants are met and that the grants will be received. The Company recognizes government grants in net income on a systematic basis and in line with recognition of the expense that the grants are intended to compensate.

Assets Held for Sale

p) Assets Held for SalePP&E and E&E assets are classified as held for sale if it is highly probable their carrying amounts will be recovered through a capital disposition rather than through future operating cash flows. Before PP&E and E&E assets are classified as held for sale, they are assessed for indicators of impairment or reversal of previously recorded impairments and are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment charges or reversals are recognized in net income. Assets held for sale are classified as current assets and are not subject to DD&A. Decommissioning liabilities associated with assets held for sale are classified as current liabilities.

Exploration and Evaluation Assets (Tables)	12 Months Ended Dec. 31, 2022
Exploration For And Evaluation Of Mineral Resources [Abstract]	

Schedule of Exploration and Evaluation Assets

($ millions)	2022
Exploration and evaluation assets at cost	1,453.4
Accumulated amortization	(1,349.2)
Net carrying amount	104.2
Reconciliation of movements during the year	
Cost, beginning of year	1,613.3
Accumulated amortization, beginning of year	(1,564.5)
Net carrying amount, beginning of year	48.8
Net carrying amount, beginning of year	48.8
Acquisitions through business combinations	28.0
Additions	134.2
Dispositions	(10.9)
Transfers to property, plant and equipment	(80.8)
Amortization	(15.2)
Foreign exchange	0.1
Net carrying amount, end of year	104.2

($ millions)	2022
Development and production assets	22,340.0
Corporate assets	126.2
Property, plant and equipment at cost	22,466.2
Accumulated depletion, depreciation and impairment	(14,736.8)
Net carrying amount	7,729.4
Reconciliation of movements during the year	
Development and production assets	
Cost, beginning of year	23,402.9
Accumulated depletion and impairment, beginning of year	(15,762.6)
Net carrying amount, beginning of year	7,640.3
Net carrying amount, beginning of year	7,640.3
Acquisitions through business combinations	66.0
Additions	741.9
Dispositions	(285.8)
Transfers from exploration and evaluation assets	80.8
Reclassified as assets held for sale	(148.4)
Depletion	(911.4)
Impairment reversal	428.6
Foreign exchange	76.2
Net carrying amount, end of year	7,688.2
Cost, end of year	22,340.0
Accumulated depletion and impairment, end of year	(14,651.8)
Net carrying amount, end of year	7,688.2
Corporate assets	
Cost, beginning of year	123.2
Accumulated depreciation, beginning of year	(76.2)
Net carrying amount, beginning of year	47.0
Net carrying amount, beginning of year	47.0
Additions	2.6
Depreciation	(8.5)
Foreign exchange	0.1
Net carrying amount, end of year	41.2
Cost, end of year	126.2
Accumulated depreciation, end of year	(85.0)
Net carrying amount, end of year	41.2

Capital Acquisitions and Dispositions (Tables)	12 Months Ended Dec. 31, 2022
Business Combinations And Dispositions [Abstract]	
Schedule of Capital Acquisitions and Dispositions	The following table summarizes the major and minor property acquisitions and dispositions:

($ millions)	Saskatchewan Viking Disposition	Kaybob Duverna Acquisitio
Cash	241.7	(87.
Consideration (paid) received	**241.7**	**(87.**
Exploration and evaluation	—	28.
Property, plant and equipment	(252.5)	61.
Goodwill	(6.8)	–
Decommissioning liability	40.2	(2.
Fair value of net assets acquired (Carrying value of net assets disposed)	**(219.1)**	**87.**
Gain on capital dispositions	**22.6**	**–**

Assets Held for Sale

($ millions)	**PP&E** (Note 8)
Assets (liabilities) held for sale	**148.4**

Property, Plant and Equipment (Tables)	12 Months Ended Dec. 31, 2022
Property, plant and equipment [abstract]	

Disclosure of property plant and equipment

($ millions)	2022
Exploration and evaluation assets at cost	1,453.4
Accumulated amortization	(1,349.2)
Net carrying amount	104.2
Reconciliation of movements during the year	
Cost, beginning of year	1,613.3
Accumulated amortization, beginning of year	(1,564.5)
Net carrying amount, beginning of year	48.8
Net carrying amount, beginning of year	48.8
Acquisitions through business combinations	28.0
Additions	134.2
Dispositions	(10.9)
Transfers to property, plant and equipment	(80.8)
Amortization	(15.2)
Foreign exchange	0.1
Net carrying amount, end of year	104.2

($ millions)	2022
Development and production assets	22,340.0
Corporate assets	126.2
Property, plant and equipment at cost	22,466.2
Accumulated depletion, depreciation and impairment	(14,736.8)
Net carrying amount	7,729.4
Reconciliation of movements during the year	
Development and production assets	
Cost, beginning of year	23,402.9
Accumulated depletion and impairment, beginning of year	(15,762.6)
Net carrying amount, beginning of year	7,640.3
Net carrying amount, beginning of year	7,640.3
Acquisitions through business combinations	66.0
Additions	741.9
Dispositions	(285.8)
Transfers from exploration and evaluation assets	80.8
Reclassified as assets held for sale	(148.4)
Depletion	(911.4)
Impairment reversal	428.6
Foreign exchange	76.2
Net carrying amount, end of year	7,688.2
Cost, end of year	22,340.0
Accumulated depletion and impairment, end of year	(14,651.8)
Net carrying amount, end of year	7,688.2
Corporate assets	
Cost, beginning of year	123.2
Accumulated depreciation, beginning of year	(76.2)
Net carrying amount, beginning of year	47.0
Net carrying amount, beginning of year	47.0
Additions	2.6
Depreciation	(8.5)
Foreign exchange	0.1
Net carrying amount, end of year	41.2
Cost, end of year	126.2
Accumulated depreciation, end of year	(85.0)
Net carrying amount, end of year	41.2

Impairment test of property, plant and equipment

The following table summarizes the total impairment reversal for the years ended December 31, 2022 and December 31, 2021:

($ millions)	2
Impairment reversal	1,54
Impairment	(98
Impairment on assets held for sale	(12
Impairment reversal	42

[Schedule of Forecast Benchmark Commodity Prices And Exchange Rates for Impairment of Property, Plant and Equipment]

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at Decem

	2023 (1)	2024	2025	2026	2027	2028	2029	2030	2
WTI ($US/bbl) (2)	80.33	78.50	76.95	77.61	79.16	80.74	82.36	84.00	85
Exchange Rate ($US/$Cdn)	0.745	0.765	0.768	0.772	0.775	0.775	0.775	0.775	0.7
WTI ($Cdn/bbl)	107.83	102.61	100.20	100.53	102.14	104.18	106.27	108.39	110
AECO ($Cdn/mmbtu) (2)	4.23	4.40	4.21	4.27	4.34	4.43	4.51	4.60	4

(1) Effective January 1, 2023.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2033 to the end of the reserve life. Exchange rates are assumed to be constant at 0.775.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at March

	2022 (1)	2023	2024	2025	2026	2027	2028	2029	2
WTI ($US/bbl) (2)	94.17	84.05	75.38	74.41	75.90	77.42	78.97	80.55	82
Exchange Rate ($US/$Cdn)	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.8
WTI ($Cdn/bbl)	117.71	105.06	94.23	93.01	94.88	96.78	98.71	100.69	102
AECO ($Cdn/mmbtu) (2)	5.18	4.18	3.38	3.34	3.41	3.48	3.54	3.61	3

(1) Effective April 1, 2022.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2032 to the end of the reserve life. Exchange rates are assumed to be constant at 0.800.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of PP&E at June 3

	2021 (1)	2022	2023	2024	2025	2026	2027	2028	2
WTI ($US/bbl) (2)	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	69
Exchange Rate ($US/$Cdn)	0.803	0.802	0.800	0.800	0.800	0.800	0.800	0.800	0.8
WTI ($Cdn/bbl)	88.83	83.79	79.94	79.04	80.63	82.24	83.88	85.55	87
AECO ($Cdn/mmbtu) (2)	3.46	3.13	2.72	2.71	2.76	2.82	2.88	2.94	2

(1) Effective July 1, 2021.

(2) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3)Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2031 to the end of the reserv are assumed to be constant at 0.800.

[Schedule of Impairment Loss and Reversal of Impairment Loss]

The following table summarizes the impairment expense for the year ended December 31, 2022 by CGU:

CGU ($ millions, except %)	Operating segment	Recoverable amount	Discount rate	Impairme
Southeast Saskatchewan	Canada	2,868.3	15.00 %	564.
Southwest Saskatchewan	Canada	1,356.6	15.00 %	420.
Total impairment		4,224.9		985.

The following table summarizes the impairment reversal for the three months ended March 31, 2022 by CGU:

CGU ($ millions, except %)	Operating segment	Recoverable amount	Discount rate	Impairment revers
Southeast Saskatchewan	Canada	3,413.8	15.00 %	806.
Southwest Saskatchewan	Canada	1,715.0	15.00 %	419.
Alberta	Canada	2,567.1	15.00 %	244.
Northern U.S.	U.S.	1,093.8	15.00 %	71.
Total impairment reversal		8,789.7		1,540.

The following table summarizes the impairment reversal for the six months ended June 30, 2021 by CGU:

CGU ($ millions, except %)	Operating segment	Recoverable amount	Discount rate	Impairment rever
Southeast Saskatchewan	Canada	2,941.0	15.00 %	91
Southwest Saskatchewan	Canada	1,422.6	15.00 %	60
Alberta [(1)]	Canada	1,911.9	15.00 %	55
Northern U.S.	U.S.	861.9	15.00 %	43
Total impairment reversal		7,137.4		2,51

(1) Previously referred to as the Southern Alberta CGU.

Schedule of Impact on Income Before Tax For Changes in Discount Rate and Forecast Benchmark Commodity Price Estimates

The following sensitivities show the resulting impact on income before tax of the changes in discount rate, forecast bench price and forecast operating cost estimates at December 31, 2022, with all other variables held constant:

CGU	Discount Rate		Commodity Prices		Op
($ millions)	Increase 1%	Decrease 1%	Increase 5%	Decrease 5%	Increase
Southeast Saskatchewan	(167.8)	185.2	349.4	(348.3)	(11
Southwest Saskatchewan	(88.0)	97.3	185.6	(185.3)	(6
Increase (decrease)	(255.8)	282.5	535.0	(533.6)	(18

The following sensitivities show the resulting impact on income before tax of the changes in discount rate and forecast benchmark commodity price 2022, with all other variables held constant:

CGU	Discount Rate		Com
($ millions)	Increase 1%	Decrease 1%	Increase
Southeast Saskatchewan	(186.2)	204.8	36
Southwest Saskatchewan	(95.0)	104.6	20
Alberta	—	—	
Northern U.S.	—	—	
Increase (decrease)	(281.2)	309.4	56

The following sensitivities show the resulting impact on income before tax of the changes in discount rate and forecast benchmark commodity price 2021, with all other variables held constant:

CGU	Discount Rate		Com
($ millions)	Increase 1%	Decrease 1%	Increase
Southeast Saskatchewan	(181.1)	199.2	35
Southwest Saskatchewan	(89.1)	97.9	18
Alberta [(1)]	(89.4)	97.2	18
Northern U.S.	(57.1)	62.9	12
Increase (decrease)	(416.7)	457.2	84

(1) Previously referred to as the Southern Alberta CGU.

Goodwill (Tables)

	12 Months Ended Dec. 31, 2022
Subclassifications of assets, liabilities and equities [abstract]	
Schedule of Goodwill Rollforward	

($ millions)	2022
Goodwill, beginning of year	211.5
Southeast Saskatchewan asset disposition	—
Saskatchewan Viking asset disposition	(6.8)
Other dispositions	(0.8)
Goodwill, end of year	203.9

Other Current Liabilities (Tables)	12 Months Ended Dec. 31, 2022
Subclassifications of assets, liabilities and equities [abstract]	
Disclosure of Other Current Liabilities	

($ millions)	2022
Long-term compensation liability	49.1
Lease liability	24.9
Decommissioning liability	41.6
Other current liabilities	115.6

Long-term Debt (Tables)

	12 Months Ended Dec. 31, 2022
Financial Instruments [Abstract]	
Schedule of Long-term Debt	

($ millions)	2022
Bank debt	**—**
Senior guaranteed notes	**1,441.5**
Long-term debt	**1,441.5**
Long-term debt due within one year	**538.7**
Long-term debt due beyond one year	**902.8**

The Company's senior guaranteed notes are detailed below:

Principal ($ millions)	Coupon Rate	Hedged Equivalent [(1)] (Cdn$ millions)	Interest Payment Dates	Maturity Date	Financial statem 2022
Cdn$25.0	4.76 %	—	November 22 and May 22	May 22, 2022	**—**
US$200.0	4.00 %	—	November 22 and May 22	May 22, 2022	**—**
US$61.5	4.12 %	80.3	October 11 and April 11	April 11, 2023	**83.2**
Cdn$80.0	3.58 %	80.0	October 11 and April 11	April 11, 2023	**80.0**
Cdn$10.0	4.11 %	10.0	December 12 and June 12	June 12, 2023	**10.0**
US$270.0	3.78 %	274.7	December 12 and June 12	June 12, 2023	**365.5**
Cdn$40.0	3.85 %	40.0	December 20 and June 20	June 20, 2024	**40.0**
US$257.5	3.75 %	276.4	December 20 and June 20	June 20, 2024	**348.5**
US$82.0	4.30 %	107.0	October 11 and April 11	April 11, 2025	**111.0**
Cdn$65.0	3.94 %	65.0	October 22 and April 22	April 22, 2025	**65.0**
US$230.0	4.08 %	291.1	October 22 and April 22	April 22, 2025	**311.3**
US$20.0	4.18 %	25.3	October 22 and April 22	April 22, 2027	**27.0**
Senior guaranteed notes		1,249.8			**1,441.5**
Due within one year		445.0			**538.7**
Due beyond one year		804.8			**902.8**

(1) Includes underlying derivatives which fix the Company's foreign exchange exposure on its US dollar senior guaranteed notes.

Leases (Tables)	12 Months Ended Dec. 31, 2022

Disclosure of leases [Abstract]

Disclosure of quantitative information about right-of-use assets

($ millions)	Office [(1)]	Fleet Vehicles	Equip
Right-of-use asset at cost	121.9	28.5	
Accumulated depreciation	(55.4)	(20.4)	
Net carrying amount	66.5	8.1	
Reconciliation of movements during the year			
Cost, beginning of year	121.6	25.2	
Accumulated depreciation, beginning of year	(44.3)	(16.1)	
Net carrying amount, beginning of year	77.3	9.1	
Net carrying amount, beginning of year	77.3	9.1	
Additions	—	3.2	
Depreciation	(10.8)	(4.2)	
Lease modification	—	—	
Net carrying amount, end of year	66.5	8.1	

(1) A portion of the Company's office space is subleased. During the year ended December 31, 2022, the Company recorded sublease income of $3.6 million (year ended December 31, 2
of other income.

Disclosure of additional information about leasing activities for lessee

($ millions)	2022
Lease liability, beginning of year	**141.4**
Additions	**3.8**
Financing	**5.7**
Payments on lease liability	**(26.1)**
Other	**(0.7)**
Lease liability, end of year	**124.1**
Expected to be incurred within one year	**24.9**
Expected to be incurred beyond one year	**99.2**

Disclosure of maturity analysis of finance lease payments receivable

The undiscounted cash flows relating to the lease liability are as follows:

($ millions)
1 year
2 to 3 years
4 to 5 years
More than 5 years
Total [(1)]

(1) Includes both the principal and amounts representing interest.

Decommissioning Liability (Tables)

12 Months Ended Dec. 31, 2022

Other Provisions, Contingent Liabilities And Contingent Assets [Abstract]

Decommissioning Liability

($ millions)	2022
Decommissioning liability, beginning of year	**918.8**
Liabilities incurred	**21.6**
Liabilities acquired through capital acquisitions	**3.4**
Liabilities disposed through capital dispositions	**(46.7)**
Liabilities settled [(1)]	**(43.1)**
Revaluation of acquired decommissioning liabilities [(2)]	**3.8**
Change in estimates	**(11.4)**
Change in discount and inflation rate estimates	**(163.0)**
Accretion	**19.2**
Reclassified as liabilities associated with assets held for sale	**(28.4)**
Foreign exchange	**1.3**
Decommissioning liability, end of year	**675.5**
Expected to be incurred within one year	**41.6**
Expected to be incurred beyond one year	**633.9**

(1) Includes $23.0 million received from government grant programs during the year ended December 31, 2022 (year ended December 31, 2021 - $28.7 million).

(2) These amounts relate to the revaluation of acquired decommissioning liabilities at the end of the period using a risk-free discount rate. At the date of acquisition, acquired decommissi

Shareholders' Capital (Tables)	12 Months Ended Dec. 31, 2022
Disclosure of classes of share capital [abstract]	
Disclosure of shareholders' capital	Crescent Point has an unlimited number of common shares authorized for issuance.

	2022		
	Number of shares	**Amount ($ millions)**	Numl s
Common shares, beginning of year	**579,484,032**	**16,963.4**	530,035
Issued on capital acquisitions	**—**	**—**	50,000
Issued on redemption of restricted shares	**1,713,730**	**5.2**	2,109
Issued on exercise of stock options	**1,038,321**	**1.4**	155
Common shares repurchased for cancellation	**(31,347,100)**	**(294.2)**	(2,817
Common shares, end of year	**550,888,983**	**16,675.8**	579,484
Cumulative share issue costs, net of tax	**—**	**(256.5)**	
Total shareholders' capital, end of year	**550,888,983**	**16,419.3**	579,484

Deficit (Tables)

12 Months Ended Dec. 31, 2022

Equity [abstract]

Schedule of Deficit

($ millions)	2022
Accumulated earnings (deficit)	(2,700.6)
Accumulated gain on shares issued pursuant to DRIP [(1)] and SDP [(2)]	8.4
Accumulated tax effect on redemption of restricted shares	15.8
Accumulated dividends	(7,886.9)
Deficit	(10,563.3)

(1) Premium Dividend TM and Dividend Reinvestment Plan – suspended in 2015.

(2) Share Dividend Plan – suspended in 2015.

Capital Management (Tables)	12 Months Ended Dec. 31, 2022
Capital Management [Abstract]	
Schedule of Capital Management	CAPITAL MANAGEMENT
Schedule of Cash Flows from Operating Activities to Adjusted Funds	The following table reconciles cash flow from operating activities to adjusted funds flow from operations for the year ended December 31, 2022 and

CAPITAL MANAGEMENT

($ millions)	2022
Long-term debt [(1)]	1,441.5
Adjusted working capital (surplus) deficiency [(2)]	(95.1)
Unrealized foreign exchange on translation of US dollar long-term debt	(191.7)
Net debt	1,154.7
Shareholders' equity	6,493.4
Total capitalization	7,648.1

(1) Includes current portion of long-term debt.

(2) Adjusted working capital (surplus) deficiency is calculated as accounts payable and accrued liabilities, dividends payable and long-term compensation liability net of equity deriva receivable and prepaids and deposits, including deposit on acquisition.

The following table reconciles cash flow from operating activities to adjusted funds flow from operations for the year ended December 31, 2022 and

($ millions)	2022
Cash flow from operating activities	2,192.2
Changes in non-cash working capital	15.0
Transaction costs	5.1
Decommissioning expenditures	20.1
Adjusted funds flow from operations	2,232.4

Commodity Derivative Losses (Tables)

Analysis of income and expense [abstract]

Schedule of Derivative Instruments

	12 Months Ended Dec. 31, 2022
($ millions)	2
Realized losses	(64
Unrealized gains (losses)	16
Commodity derivative losses	(47

Other Income (Loss) (Tables)

	12 Months Ended Dec. 31, 2022

Analysis of income and expense [abstract]

Schedule of Other Income (Loss)

($ millions)	20
Unrealized gain on long-term investments	
Realized gain on sale of long-term investments	
Gain on capital dispositions	25
Government grant for decommissioning expenditures	23
Sublease income	3
Other	[illegible]
Other income	58

Interest Expense (Tables)	12 Months Ended Dec. 31, 2022
Analysis of income and expense [abstract]	
Schedule of Interest Expense	

($ millions)	2
Interest expense on long-term debt	6
Unrealized (gain) loss on interest derivative contracts	(
Interest expense	6

Foreign Exchange Gain (Tables)	12 Months Ended Dec. 31, 2022
Foreign exchange rates [abstract]	
Foreign Exchange Gain (Loss)	

($ millions)	2
Realized gain on CCS - principal	6
Translation of US dollar long-term debt	(9
Unrealized gain (loss) on CCS - principal and foreign exchange swaps	
Other	
Foreign exchange gain (loss)	(1

Income Taxes (Tables)	**12 Months Ended Dec. 31, 2022**
Income Taxes [Abstract]	
Disclosure of provision for income taxes	The provision for income taxes is as follows:

($ millions)	2
Current tax:	
Canada	
United States	
Current tax expense	
Deferred tax expense (recovery):	
Canada	41
United States	(2
Deferred tax expense	38
Income tax expense	38

Disclosure of reconciliation of income taxes calculated at the Canadian statutory rate with recorded income taxes

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions, except percentages)	20
Net income before tax	1,871.3
Statutory income tax rate	24.82
Expected provision for income taxes	464.5
Change in corporate tax rates and tax rate variance	1.6
Tax rates in foreign jurisdictions	2.1
Restricted share bonus plan	0.6
Recognition of deferred tax assets	(83.2)
Derecognition of deferred tax assets	—
Non-taxable capital gains	(0.2)
Non-deductible disposition of goodwill	1.9
Other	0.6
Income tax expense	387.9

Net deferred income tax asset

The composition of the net deferred income tax asset is as follows:

($ millions)	2
Deferred income tax assets	27
Deferred income tax liabilities	(7
Net deferred income tax asset	20

Disclosure of net deferred tax liabilities

The net deferred income tax assets (liabilities) are expected to be settled in the following periods:

($ millions)	2
Deferred income tax:	
To be settled within one year	1
To be settled beyond one year	18
Deferred income tax	20

The movement in deferred income tax assets (liabilities) are as follows:

($ millions)	At January 1, 2022	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings
Deferred income tax assets:			
Property, plant and equipment	—	—	—
Decommissioning liability	229.6	—	(62.2)
Income tax losses carried forward	814.2	—	(69.6)
Risk management contracts	41.1	—	(39.0)
Lease liabilities	35.3	—	(4.6)
Other	19.5	19.3	(8.9)
	1,139.7	19.3	(184.3)
Deferred income tax liabilities:			
Property, plant and equipment	(533.4)	—	(209.7)
Risk management contracts	(13.4)	—	2.6
ROU asset	(22.8)	—	3.5
	(569.6)	—	(203.6)
Net deferred income tax assets (liabilities)	570.1	19.3	(387.9)

($ millions)	At January 1, 2021	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings
Deferred income tax assets:			
Property, plant and equipment	248.9	—	(248.9)
Decommissioning liability	262.2	—	(32.6)
Income tax losses carried forward	833.1	—	(18.9)
Risk management contracts	11.6	—	29.5
Lease liabilities	40.1	—	(4.8)
Other	8.5	1.9	9.1
	1,404.4	1.9	(266.6)
Deferred income tax liabilities:			
Property, plant and equipment	—	—	(533.4)
Risk management contracts	(9.9)	—	(3.5)
ROU asset	(26.6)	—	3.8
	(36.5)	—	(533.1)
Net deferred income tax assets (liabilities)	1,367.9	1.9	(799.7)

Disclosure of tax pools available

The approximate amounts of tax pools available as at December 31, 2022 and 2021 are as follows:

($ millions)	2
Tax pools:	
Canada	**5,68**
United States	**3,02**
Total	**8,71**

Share-based Compensation (Tables)	12 Months Ended Dec. 31, 2022
Share-based Payment Arrangements [Abstract]	
Schedule of restricted shares and DSU's rollforward	The following table reconciles the number of restricted shares, ESVP awards, PSUs and DSUs for the year ended December 31, 2022:

	Restricted Shares	ESVP	PSUs [1]
Balance, beginning of year	3,267,717	8,329,291	3,214,620
Granted	710,819	1,288,598	904,469
Redeemed	(1,718,906)	(3,691,820)	(1,405,913)
Forfeited	(14,892)	(651,591)	—
Balance, end of year	2,244,738	5,274,478	2,713,176

(1) Based on underlying units before any effect of performance multipliers.

The following table reconciles the number of restricted shares, ESVP awards, PSUs and DSUs for the year ended December 31, 2021:

	Restricted Shares	ESVP	PSUs [1]
Balance, beginning of year	4,704,129	10,449,383	3,789,689
Granted	1,230,133	2,570,746	2,053,574
Redeemed	(2,146,716)	(3,417,496)	(2,221,058)
Forfeited	(519,829)	(1,273,342)	(407,585)
Balance, end of year	3,267,717	8,329,291	3,214,620

(1) Based on underlying units before any effect of performance multipliers.

The following table provides summary information regarding stock options outstanding as at December 31, 2022:

	Stock Options (number of units)	Weight
Balance, beginning of year	5,839,464	
Exercised	(1,446,571)	
Forfeited	(398,610)	
Expired	(105,153)	
Balance, end of year	3,889,130	

Summarized Information Regarding Stock Options Outstanding

The following table summarizes information regarding stock options outstanding as at December 31, 2022:

Range of exercise prices ($)	Number of stock options outstanding	Weighted average remaining term for options outstanding (years)	Weighted average exercise price per share for options outstanding ($)	Number of stock options exercisable
1.09 - 1.65	1,884,156	4.25	1.09	307,638
1.66 - 5.16	470,946	3.26	3.92	137,543
5.17 - 9.86	505,809	4.77	5.91	113,490
9.87 - 10.06	1,028,219	2.02	10.06	1,028,219
	3,889,130	3.61	4.43	1,586,890

Disclosure of Number and Weighted Average Exercise Prices of Share Options

The following table provides summary information regarding stock options outstanding as at December 31, 2021:

	Stock Options (number of units)	Weight
Balance, beginning of year	5,940,871	
Granted	534,264	
Exercised	(261,486)	
Forfeited	(285,047)	
Expired	(89,138)	
Balance, end of year	5,839,464	

Per Share Amounts (Tables)	12 Months Ended Dec. 31, 2022
Earnings per share [abstract]	
Disclosure of earnings per share	The following table summarizes the weighted average shares used in calculating net income per share:

	2022
Weighted average shares – basic	566,710,644
Dilutive impact of share-based compensation	4,357,422
Weighted average shares – diluted	571,068,066

Financial Instruments and Derivatives (Tables)	12 Months Ended Dec. 31, 2022
Financial Instruments [Abstract]	
Disclosure of financial assets	(see below)

Disclosure of financial assets

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair v
2022:

($ millions)	2022 Carrying Value	2022 Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant oth observable inpu (Level
Financial assets				
Derivatives	235.3	235.3	—	235.
	235.3	235.3	—	235.
Financial liabilities				
Derivatives	8.7	8.7	—	8.
Senior guaranteed notes (1)	1,441.5	1,372.9	—	1,372.
	1,450.2	1,381.6	—	1,381.

(1) The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair v
2021:

($ millions)	2021 Carrying Value	2021 Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant oth observable inpu (Level
Financial assets				
Derivatives	220.5	220.5	—	220.
	220.5	220.5	—	220.
Financial liabilities				
Derivatives	164.9	164.9	—	164.
Senior guaranteed notes (1)	1,638.8	1,618.4	—	1,618.
	1,803.7	1,783.3	—	1,783.

(1)The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. T in US dollars are translated to Canadian dollars at the period end exchange rate. The fair value of the notes is calculated b interest rates and is not recorded in the financial statements.

Disclosure of financial liabilities

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair v
2022:

($ millions)	2022 Carrying Value	2022 Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant oth observable inpu (Level
Financial assets				
Derivatives	235.3	235.3	—	235.
	235.3	235.3	—	235.
Financial liabilities				
Derivatives	8.7	8.7	—	8.
Senior guaranteed notes (1)	1,441.5	1,372.9	—	1,372.
	1,450.2	1,381.6	—	1,381.

(1) The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair v
2021:

($ millions)	2021 Carrying Value	2021 Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant othe observable inpu (Level
Financial assets				
Derivatives	220.5	220.5	—	220.
	220.5	220.5	—	220.
Financial liabilities				
Derivatives	164.9	164.9	—	164.
Senior guaranteed notes (1)	1,638.8	1,618.4	—	1,618.
	1,803.7	1,783.3	—	1,783.

(1)The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. T in US dollars are translated to Canadian dollars at the period end exchange rate. The fair value of the notes is calculated b interest rates and is not recorded in the financial statements.

Disclosure of derivative assets and liabilities

The following table summarizes the fair value as at December 31, 2022 and the change in fair value for the year ended December 31, 2022:

($ millions)	Commodity (1)	Interest (2)	Foreign exchange (3)
Derivative assets (liabilities), beginning of year	(154.4)	5.6	170.6
Unrealized change in fair value	168.4	1.1	4.4
Derivative assets, end of year	14.0	6.7	175.0
Derivative assets, end of year	22.6	6.7	175.1
Derivative liabilities, end of year	(8.6)	—	(0.1)

(1) Includes crude oil, crude oil differentials, propane, natural gas and natural gas differential contracts.

(2) Interest payments on CCS.

(3) Includes principal portion of CCS and foreign exchange contracts.

The following table summarizes the fair value as at December 31, 2021 and the change in fair value for the year ended December 31, 2021:

($ millions)	Commodity (1)	Interest (2)	Foreign exchange (3)
Derivative assets (liabilities), beginning of year	(26.3)	7.3	205.0
Unrealized change in fair value	(128.1)	(1.7)	(34.4)
Derivative assets (liabilities), end of year	(154.4)	5.6	170.6
Derivative assets, end of year	5.4	5.7	175.6
Derivative liabilities, end of year	(159.8)	(0.1)	(5.0)

(1) Includes crude oil, crude oil differentials, propane, natural gas and natural gas differential contracts.

(2) Interest payments on CCS and interest derivative contracts.

(3) Includes principal portion of CCS and foreign exchange contracts.

Disclosure of offsetting of financial assets and liabilities

The following table summarizes the gross asset and liability positions of the Company's financial derivatives by contract t balance sheet as at December 31, 2022 and December 31, 2021:

			2022		
($ millions)	Asset	Liability	Net	Asset	Li
Gross amount	246.3	(19.7)	226.6	218.9	(1
Amount offset	(11.0)	11.0	—	1.6	
Net amount	235.3	(8.7)	226.6	220.5	(1

Sensitivity analysis for types of market risk

The following table summarizes the unrealized gains (losses) on the Company's commodity financial derivative contracts and the resulting impact o fluctuations in commodity prices or differentials, with all other variables held constant:

	Impact on Income Before Tax		
($ millions)	Year ended December 31, 2022		Ye
	Increase 10%	Decrease 10%	Increase 1
Commodity price			
Crude oil and condensate	(40.3)	38.8	(14
Natural gas	(3.1)	3.2	(
Differential			
Natural gas	2.6	(2.6)	

The following table summarizes the resulting unrealized gains (losses) impacting income before tax due to the respective changes in the period en exchange rates, with all other variables held constant:

		Impact on Income Before Tax		
($ millions)	Exchange Rate	Year ended December 31, 2022		Ye
Cdn$ relative to US$		Increase 10%	Decrease 10%	Increase 1
US dollar long-term debt	Period End	124.6	(124.6)	16
Cross currency swaps	Forward	(123.7)	123.7	(16
Foreign exchange swaps	Forward	4.3	(4.3)	(

The following table summarizes the unrealized gains (losses) on the Company's equity derivative contracts and the resulting impact on income bef respective changes in the applicable share price, with all other variables held constant:

	Impact on Income Before Tax		
($ millions)	Year ended December 31, 2022		Ye
Share price	Increase 50%	Decrease 50%	Increase 5
Total return swaps	26.8	(26.8)	2

Disclosure of undiscounted cash outflows to non-derivative financial liabilities

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2022, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5
Accounts payable and accrued liabilities	448.2	—	—	
Dividends payable	99.4	—	—	
Derivative liabilities (1)	12.6	—	—	
Senior guaranteed notes (2)	486.6	816.2	26.9	

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS related to the senior guaranteed notes, which fix the amounts due in Canadian dollars.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2021, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5
Accounts payable and accrued liabilities	450.7	—	—	
Dividends payable	43.5	—	—	
Derivative liabilities (1)	249.0	1.1	0.3	
Senior guaranteed notes (2)	280.3	829.2	474.6	
Bank credit facilities (3)	11.7	23.5	346.3	

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS and foreign exchange swap related to the senior guaranteed notes, which fix the amounts du

(3) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2021 and includes undiscounted cash outflows pursuant to the CCS related

Disclosure of undiscounted cash outflows to derivative financial liabilities

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2022, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5
Accounts payable and accrued liabilities	448.2	—	—	
Dividends payable	99.4	—	—	
Derivative liabilities (1)	12.6	—	—	
Senior guaranteed notes (2)	486.6	816.2	26.9	

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS related to the senior guaranteed notes, which fix the amounts due in Canadian dollars.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2021, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5
Accounts payable and accrued liabilities	450.7	—	—	
Dividends payable	43.5	—	—	
Derivative liabilities (1)	249.0	1.1	0.3	
Senior guaranteed notes (2)	280.3	829.2	474.6	
Bank credit facilities (3)	11.7	23.5	346.3	

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS and foreign exchange swap related to the senior guaranteed notes, which fix the amounts du

(3) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2021 and includes undiscounted cash outflows pursuant to the CCS related

Disclosure of derivative contracts

The following is a summary of the derivative contracts in place as at December 31, 2022:

Financial WTI Crude Oil Derivative Contracts – Canadian Dollar (1)							
	Swap		Collar			Three-way Co	
Term	Volume (bbls/d)	Average Price ($/bbl)	Volumes (bbls/d)	Average Sold Call Price ($/bbl)	Average Bought Put Price ($/bbl)	Volume (bbls/d)	Average Sold Call Price ($/bbl)
2023	1,356	90.04	10,586	114.99	101.39	616	118.11

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial AECO Natural Gas Derivative Contracts – Canadian Dollar (1)				
	Swap		Collar	
Term	Volume (GJ/d)	Average Price ($/GJ)	Volume (GJ/d)	Average Sold Call Price ($/GJ)
2023	21,605	4.68	7,397	10.21
2024 January - March	10,000	5.13	—	—

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial NYMEX Natural Gas Differential Derivative Contracts – US Dollar (1)			
Term	Volume (mmbtu/d)	Contract	Basis
January 2023 - March 2025	17,500	Basis Swap	AECO

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial Cross Currency Derivative Contracts				
Term	Contract	Receive Notional Principal (US$ millions)	Fixed Rate (US%)	Pay Notional Principal (Cdn$ millions)
January 2023 - April 2023	Swap	61.5	4.12	80.3
January 2023 - June 2023	Swap	270.0	3.78	274.7
January 2023 - June 2024	Swap	257.5	3.75	276.4
January 2023 - April 2025	Swap	82.0	4.30	107.0
January 2023 - April 2025	Swap	230.0	4.08	291.1
January 2023 - April 2027	Swap	20.0	4.18	25.3

Financial Foreign Exchange Forward Derivative Contracts				
Settlement Date	Contract	Receive Currency	Receive Notional Principal ($ millions)	Curre
January 2023	Swap	US$	15.0	C
January 2023	Swap [1]	Cdn$	63.9	U

(1) Based on an average floating exchange rate.

Financial Equity Derivative Contracts		
Term	Contract	Notional Principal ($ millions)
January 2023 - April 2023	Swap	11.9
January 2023 - April 2024	Swap	7.2
January 2023 - April 2025	Swap	3.6

Commitments (Tables)	12 Months Ended Dec. 31, 2022
Capital commitments [abstract]	
Schedule of Gain Contingencies by Contingency	At December 31, 2022, the Company had contractual obligations and commitments as follows:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 yea
Operating [(1)]	11.7	15.7	9.8	11
Gas processing	64.6	105.4	88.5	291
Transportation	43.3	74.8	41.5	40
Capital	7.3	—	—	-
Total contractual commitments [(2)]	126.9	195.9	139.8	343

(1) Includes operating costs on the Company's office space, net of $18.1 million recoveries from subleases.

(2) Excludes contracts accounted for under IFRS 16. See Note 12 - "Leases" for additional information.

Significant Subsidiaries (Tables)	12 Months Ended Dec. 31, 2022
Disclosure of subsidiaries [abstract]	
Schedule of Significant Subsidiaries Owned	The Company has the following significant subsidiaries, each owned 100% directly and indirectly, at December 31, 2022: **Subsidiary Name** Crescent Point Resources Partnership Crescent Point Holdings Ltd. Crescent Point Energy U.S. Corp. Crescent Point U.S. Holdings Corp.

Supplemental Disclosures (Tables)	12 Months Ended Dec. 31, 2022
Supplemental Disclosures [Abstract]	
Income statement presentation	The Company’s statements of comprehensive income are prepared primarily by nature of expense, with the exception of compensation expenses w operating, general and administrative and share-based compensation line items, as follows:

($ millions)	2
Operating	6
General and administrative	6
Share-based compensation	3
Total compensation expenses	15

Cash flow statement presentation

Cash flow statement presentation

($ millions)	2
Operating activities	
Changes in non-cash working capital:	
Accounts receivable	(1
Prepaids and deposits	(1
Accounts payable and accrued liabilities	(
Other current liabilities	
Other long-term liabilities	
	(1
Investing activities	
Changes in non-cash working capital:	
Accounts receivable	
Other long-term receivable	
Accounts payable and accrued liabilities	(
	(
Financing activities	
Changes in non-cash working capital:	
Prepaids and deposits	(4
Accounts payable and accrued liabilities	
Dividends payable	5
	1

The Company's reconciliation of cash flow from financing activities is outlined in the table below:

($ millions)	Dividends payable	Long-term debt (1)
December 31, 2020	1.3	2,259.6
Changes from cash flow from financing activities:		
Decrease in bank debt, net		(34.6)
Repayment of senior guaranteed notes		(217.6)
Dividends paid	(5.6)	
Payments on principal portion of lease liability		
Non-cash changes:		
Dividends declared	47.8	
Additions		
Other		
Foreign exchange		(37.2)
December 31, 2021	43.5	1,970.2
Changes from cash flow from financing activities:		
Decrease in bank debt, net		**(338.5)**
Repayment of senior guaranteed notes		**(281.8)**
Realized gain on cross currency swap maturity		**63.8**
Dividends paid	**(144.7)**	
Payments on principal portion of lease liability		
Non-cash changes:		
Dividends declared	**200.6**	
Additions		
Other		
Foreign exchange		**27.8**
December 31, 2022	**99.4**	**1,441.5**

(1) Includes current portion of long-term debt.

(2) Includes current portion of lease liability.

Geographical Disclosure (Tables)	12 Months Ended Dec. 31, 2022
Disclosure of geographical areas [abstract]	
Disclosure of disaggregation of revenue from contracts with customers	The following table reconciles oil and gas sales by country:

($ millions) (1)	2
Canada	
Crude oil and condensate sales	**3,31**
NGL sales	**22**
Natural gas sales	**30**
Total Canada	**3,84**
U.S.	
Crude oil and condensate sales	**55**
NGL sales	**5**
Natural gas sales	**3**
Total U.S.	**64**
Total oil and gas sales	**4,49**

(1) Oil and gas sales are reported before realized derivatives.

The following table reconciles non-current assets by country:

($ millions)	2022
Canada	**6,977.9**
U.S.	**1,519.3**
Total	**8,497.2**

Basis of Preparation (Details)	12 Months Ended Dec. 31, 2022 segment
Corporate Information And Statement of IFRS Compliance [Abstract]	
Number of reportable segments	1

Significant Accounting Policies (Details)	12 Months Ended Dec. 31, 2022
Restricted Share Bonus Plan	
Disclosure of detailed information about property, plant and equipment [line items]	
Award vesting (in years)	3 years
Employee Share Value Plan	
Disclosure of detailed information about property, plant and equipment [line items]	
Award vesting (in years)	3 years
Performance Share Units	
Disclosure of detailed information about property, plant and equipment [line items]	
Award vesting (in years)	3 years
Minimum	
Disclosure of detailed information about property, plant and equipment [line items]	
Estimated useful lives	5 years
Maximum	
Disclosure of detailed information about property, plant and equipment [line items]	
Estimated useful lives	16 years
Maximum | Deferred Share Units	
Disclosure of detailed information about property, plant and equipment [line items]	
Award vesting (in years)	7 years

(Other Long-term Assets) (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
Subclassifications of assets, liabilities and equities [abstract]		
Non-current receivables from taxes other than income tax	$ 6.4	$ 6.4

Exploration and Evaluation Assets (Details) - CAD ($) $ in Millions	3 Months Ended	12 Months Ended	
	Mar. 31, 2022	Dec. 31, 2022	Dec. 31, 2021
Disclosure of detailed information about property, plant and equipment [line items]			
Beginning of period	$ 7,687.3	$ 7,687.3	
End of period		7,729.4	$ 7,687.3
Impairment reversal	1,540.9		
Gross carrying amount			
Disclosure of detailed information about property, plant and equipment [line items]			
Beginning of period	23,526.1	23,526.1	
End of period		22,466.2	23,526.1
Exploration and evaluation assets			
Disclosure of detailed information about property, plant and equipment [line items]			
Beginning of period	48.8	48.8	86.4
Acquisitions through business combinations		28.0	18.6
Additions		134.2	57.8
Dispositions		(10.9)	(5.4)
Transfers to property, plant and equipment		(80.8)	(57.5)
Amortization		(15.2)	(51.0)
Foreign exchange		0.1	(0.1)
End of period		104.2	48.8
Impairment reversal		0.0	0.0
Exploration and evaluation assets | Gross carrying amount			
Disclosure of detailed information about property, plant and equipment [line items]			
Beginning of period	1,613.3	1,613.3	1,736.1
End of period		1,453.4	1,613.3
Exploration and evaluation assets | Accumulated depreciation and amortisation			
Disclosure of detailed information about property, plant and equipment [line items]			
Beginning of period	$ (1,564.5)	(1,564.5)	(1,649.7)
End of period		$ (1,349.2)	$ (1,564.5)

Capital Acquisitions and Dispositions (Narrative) (Details) - CAD ($) $ in Millions			12 Months Ended	
	Aug. 31, 2022	Jul. 06, 2022	Dec. 31, 2022	Dec. 31, 2021
Kaybob Duvernay				
Disclosure of impairment loss and reversal of impairment loss [line items]				
Consideration, net	$ 87.0			
Carrying value	87.0			
Gain on capital dispositions	$ 0.0			
Acquisition-related costs recognised as expense for transaction recognised separately from acquisition of assets and assumption of liabilities in business combination			$ 5.1	$ 12.5
Gain on capital dispositions			25.9	$ 58.4
Other Minor Dispositions				
Disclosure of impairment loss and reversal of impairment loss [line items]				
Consideration, net			(38.2)	
Carrying value			(34.9)	
Gain on capital dispositions			$ (3.3)	
Saskatchewan Viking Disposition				
Disclosure of impairment loss and reversal of impairment loss [line items]				
Consideration, net		$ (241.7)		
Carrying value		(219.1)		
Gain on capital dispositions		$ (22.6)		

Capital Acquisitions and Dispositions (Schedule of Minor Acquisitions and Dispositions) (Details) - CAD ($) $ in Millions	Aug. 31, 2022	Jul. 06, 2022	12 Months Ended Dec. 31, 2022
Saskatchewan Viking Disposition			
Disclosure of impairment loss and reversal of impairment loss [line items]			
Cash		$ 241.7	
Consideration (paid) received		241.7	
Exploration and evaluation		0.0	
Property, plant and equipment		(252.5)	
Goodwill		(6.8)	
Decommissioning liability		40.2	
Fair value of net assets acquired (Carrying value of net assets disposed)		(219.1)	
Gain on capital dispositions		$ 22.6	
Kaybob Duvernay			
Disclosure of impairment loss and reversal of impairment loss [line items]			
Cash	$ (87.0)		
Consideration (paid) received	(87.0)		
Exploration and evaluation	28.0		
Property, plant and equipment	61.8		
Goodwill	0.0		
Decommissioning liability	(2.8)		
Fair value of net assets acquired (Carrying value of net assets disposed)	87.0		
Gain on capital dispositions	$ 0.0		
Other Minor Dispositions			
Disclosure of impairment loss and reversal of impairment loss [line items]			
Cash			$ 38.2
Consideration (paid) received			38.2
Exploration and evaluation			(10.9)
Property, plant and equipment			(29.1)
Goodwill			(0.8)
Decommissioning liability			5.9
Fair value of net assets acquired (Carrying value of net assets disposed)			(34.9)
Gain on capital dispositions			$ 3.3

Capital Acquisitions and Dispositions (Assets Held for Sale) (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
Business Combinations And Dispositions [Abstract]		
Assets held for sale	$ 148.4	
Liabilities held for sale	$ (28.4)	$ 0.0

Property, Plant and Equipment (Schedule of Property, Plant and Equipment) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	$ 7,687.3	
End of period	7,729.4	$ 7,687.3
General and administrative costs capitalized	49.7	45.1
Share-based compensation expense capitalized	14.7	14.3
Gross carrying amount		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	23,526.1	
End of period	22,466.2	23,526.1
Accumulated depreciation, amortization and impairment		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	(15,838.8)	
End of period	(14,736.8)	(15,838.8)
Development And Production Assets		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	7,640.3	4,318.9
Acquisitions through business combinations	66.0	953.8
Additions	741.9	736.5
Dispositions	(285.8)	(243.7)
Transfers from exploration and evaluation assets	80.8	57.5
Reclassified as assets held for sale	(148.4)	0.0
Depletion	(911.4)	(708.5)
Impairment reversal	428.6	2,514.4
Foreign exchange	76.2	11.4
End of period	7,688.2	7,640.3
Development And Production Assets | Gross carrying amount		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	23,402.9	23,584.1
End of period	22,340.0	23,402.9
Development And Production Assets | Accumulated depreciation, amortization and impairment		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	(15,762.6)	(19,265.2)
End of period	(14,651.8)	(15,762.6)
Corporate Assets		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	47.0	53.1
Additions	2.6	2.5

Depletion	(8.5)	(8.6)
Foreign exchange	0.1	0.0
End of period	41.2	47.0
Corporate Assets | Gross carrying amount		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	123.2	120.7
End of period	126.2	123.2
Corporate Assets | Accumulated depreciation, amortization and impairment		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	(76.2)	(67.6)
End of period	(85.0)	(76.2)
Future Development Costs		
Reconciliation of changes in property, plant and equipment [abstract]		
Beginning of period	4,580.0	
End of period	$ 5,160.0	$ 4,580.0

Property, Plant and Equipment (Impairment Reversal) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Property, plant and equipment [abstract]		
Impairment reversal	$ 1,540.9	$ 2,514.4
Impairment	(985.0)	0.0
Impairment on assets held for sale	(127.3)	0.0
Impairment reversal	$ 428.6	$ 2,514.4

Property, Plant and Equipment (Assets Held for Sale) (Details) - CAD ($) $ in Millions	3 Months Ended	12 Months Ended
	Mar. 31, 2022	Dec. 31, 2022
Property, plant and equipment [abstract]		
Impairment loss	$ 56.0	$ 71.3

Property, Plant and Equipment (Impairment Test of Property, Plant and Equipment) (Details) $ in Millions	3 Months Ended Mar. 31, 2022 CAD ($) $ / bbl	Dec. 31, 2022 CAD ($)	Dec. 31, 2022 $ / bbl	Dec. 31, 2022 $ / $	Dec. 31, 2022 $ / bbl	Dec. 31, 2022 $ / MMbtu	Dec. 31, 2022	Mar. 31, 2022 $ / $	Mar. 31, 2022 $ / bbl	Mar. 31, 2022 $ / MMbtu	Dec. 31, 2021	Jun. 30, 2021 $ / bbl	Jun. 30, 2021 $ / $	Jun. 30, 2021 $ / bbl	Jun. 30, 2021 $ / MMbtu	Jun. 30, 2021
Disclosure of detailed information about property, plant and equipment [line items]																
Forecast benchmark commodity price, assumed annual increase, percent							2.00%				2.00%					2.00%
Impairment reversal | $	$ 1,540.9															
Forecast benchmark, commodity price, assumed exchanged rate																80.00%
Saskatchewan Viking Disposition																
Disclosure of detailed information about property, plant and equipment [line items]																
After tax impairment losses that can be reversed in future periods | $		$ 1,490.0														
Southwest Saskatchewan																
Disclosure of detailed information about property, plant and equipment [line items]																
After tax impairment losses that can be reversed in future periods | $		1,090.0														
Alberta																
Disclosure of detailed information about property, plant and equipment [line items]																
After tax impairment losses that can be reversed in future periods | $		0.0														
Northern U.S.																
Disclosure of detailed information about property, plant and equipment [line items]																
After tax impairment losses that can be reversed in future periods | $		$ 0.0														
2021 | WTI Derivative Contracts – Canadian Dollar																
Disclosure of detailed information about property, plant and equipment [line items]																

Forecast benchmark, commodity prices									71.33		88.83	
Closing foreign exchange rate | $ / $										0.803		
2021 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu												3.46
2022 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	94.17						117.71		67.20		83.79	
Closing foreign exchange rate | $ / $						0.800				0.802		
2022 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu								5.18				3.13
2023 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	84.05	80.33		107.83			105.06		63.95		79.94	
Closing foreign exchange rate | $ / $			0.745			0.800				0.800		
2023 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.23			4.18				2.72
2024 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	75.38	78.50		102.61			94.23		63.23		79.04	

Closing foreign exchange rate | $ / $			0.765			0.800				0.800		
2024 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.40			3.38				2.71
2025 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	74.41	76.95		100.20			93.01		64.50		80.63	
Closing foreign exchange rate | $ / $			0.768			0.800				0.800		
2025 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.21			3.34				2.76
2026 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	75.90	77.61		100.53			94.88		65.79		82.24	
Closing foreign exchange rate | $ / $			0.772			0.800				0.800		
2026 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.27			3.41				2.82
2027 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	77.42	79.16		102.14			96.78		67.10		83.88	
Closing foreign exchange rate | $ / $			0.775			0.800				0.800		

2027 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.34			3.48				2.88
2028 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	78.97	80.74		104.18			98.71		68.44		85.55	
Closing foreign exchange rate | $ / $			0.775			0.800				0.800		
2028 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.43			3.54				2.94
2029 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	80.55	82.36		106.27			100.69		69.81		87.26	
Closing foreign exchange rate | $ / $			0.775			0.800				0.800		
2029 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.51			3.61				2.99
2030 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	82.16	84.00		108.39			102.70		71.21		89.01	
Closing foreign exchange rate | $ / $			0.775			0.800				0.800		
2030 | AECO Natural Gas Derivative Contracts – Canadian Dollar												

Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.60			3.69				3.05
2031 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	83.80	85.69		110.57			104.75		72.63		90.79	
Closing foreign exchange rate | $ / $			0.775			0.800				0.800		
2031 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.69			3.76				3.12
2032 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices	85.48	87.40		112.77			106.85					
Closing foreign exchange rate | $ / $			0.775			0.800						
2032 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices | $ / MMbtu					4.79			3.84				
2033 | WTI Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property, plant and equipment [line items]												
Forecast benchmark, commodity prices		89.15		115.03								
Closing foreign exchange rate | $ / $			0.775									
2033 | AECO Natural Gas Derivative Contracts – Canadian Dollar												
Disclosure of detailed information about property,												

plant and equipment [line items]	
Forecast benchmark, commodity prices | $ / MMbtu	4.88

Property, Plant and Equipment (Impairment Loss and Recovery) (Details) - CAD ($) $ in Millions	3 Months Ended Mar. 31, 2022	6 Months Ended Jun. 30, 2021	12 Months Ended Dec. 31, 2022
Disclosure of impairment loss and reversal of impairment loss [line items]			
Recoverable amount	$ 8,789.7	$ 7,137.4	
Impairment reversal		2,514.4	
Impairment reversal, net of tax	1,156.3	1,883.7	
Impairment reversal	1,540.9		
Canada			
Disclosure of impairment loss and reversal of impairment loss [line items]			
Recoverable amount			$ 4,224.9
Impairment reversal, net of tax			740.5
Impairment reversal			985.0
Saskatchewan Viking Disposition | Canada			
Disclosure of impairment loss and reversal of impairment loss [line items]			
Recoverable amount	$ 3,413.8	$ 2,941.0	$ 2,868.3
Discount rate	15.00%	15.00%	15.00%
Impairment reversal		$ 917.7	
Impairment reversal, net of tax	$ 605.3	688.1	$ 424.4
Impairment reversal	806.0		564.5
Southwest Saskatchewan | Canada			
Disclosure of impairment loss and reversal of impairment loss [line items]			
Recoverable amount	$ 1,715.0	$ 1,422.6	$ 1,356.6
Discount rate	15.00%	15.00%	15.00%
Impairment reversal		$ 604.1	
Impairment reversal, net of tax	$ 315.0	453.0	$ 316.1
Impairment reversal	419.4		$ 420.5
Alberta | Canada			
Disclosure of impairment loss and reversal of impairment loss [line items]			
Recoverable amount	$ 2,567.1	$ 1,911.9	
Discount rate	15.00%	15.00%	
Impairment reversal		$ 555.6	
Impairment reversal, net of tax	$ 183.4	416.6	
Impairment reversal	244.2		
Northern U.S. | U.S.			
Disclosure of impairment loss and reversal of impairment loss [line items]			

Recoverable amount	$ 1,093.8	$ 861.9
Discount rate	15.00%	15.00%
Impairment reversal		$ 437.0
Impairment reversal, net of tax	$ 52.6	$ 326.0
Impairment reversal	$ 71.3	

Property, Plant and Equipment (Market Risk) (Details) - CAD ($) $ in Millions	3 Months Ended Mar. 31, 2022	6 Months Ended Jun. 30, 2021	12 Months Ended Dec. 31, 2022
Discount Rate Increase 1%			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	$ (281.2)	$ (416.7)	$ (255.8)
Discount Rate Increase 1% | Saskatchewan Viking Disposition			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	(186.2)	(181.1)	(167.8)
Discount Rate Increase 1% | Southwest Saskatchewan			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	(95.0)	(89.1)	(88.0)
Discount Rate Increase 1% | Alberta			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	0.0	(89.4)	
Discount Rate Increase 1% | Northern U.S.			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	0.0	(57.1)	
Discount Rate Decrease 1%			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	309.4	457.2	282.5
Discount Rate Decrease 1% | Saskatchewan Viking Disposition			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	204.8	199.2	185.2
Discount Rate Decrease 1% | Southwest Saskatchewan			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	104.6	97.9	97.3
Discount Rate Decrease 1% | Alberta			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	0.0	97.2	
Discount Rate Decrease 1% | Northern U.S.			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	0.0	62.9	

Commodity Prices Increase 5%			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	568.7	848.0	535.0
Commodity Prices Increase 5% | Saskatchewan Viking Disposition			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	367.6	350.7	349.4
Commodity Prices Increase 5% | Southwest Saskatchewan			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	201.1	183.4	185.6
Commodity Prices Increase 5% | Alberta			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	0.0	189.9	
Commodity Prices Increase 5% | Northern U.S.			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	0.0	124.0	
Commodity Prices Decrease 5%			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	(567.7)	(847.0)	(533.6)
Commodity Prices Decrease 5% | Saskatchewan Viking Disposition			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	(366.6)	(349.9)	(348.3)
Commodity Prices Decrease 5% | Southwest Saskatchewan			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	(201.1)	(182.7)	(185.3)
Commodity Prices Decrease 5% | Alberta			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	0.0	(190.3)	
Commodity Prices Decrease 5% | Northern U.S.			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings	$ 0.0	$ (124.1)	
Operating Costs Increases 5%			
Disclosure of nature and extent of risks arising from financial instruments [line items]			
Possible change in risk variable, impact on pre-tax earnings			(182.5)
Operating Costs Increases 5% | Saskatchewan Viking Disposition			

Disclosure of nature and extent of risks arising from financial instruments [line items]	
Possible change in risk variable, impact on pre-tax earnings	(117.7)
Operating Costs Increases 5% | Southwest Saskatchewan	
Disclosure of nature and extent of risks arising from financial instruments [line items]	
Possible change in risk variable, impact on pre-tax earnings	(64.8)
Operating Costs Decreases 5%	
Disclosure of nature and extent of risks arising from financial instruments [line items]	
Possible change in risk variable, impact on pre-tax earnings	183.7
Operating Costs Decreases 5% | Saskatchewan Viking Disposition	
Disclosure of nature and extent of risks arising from financial instruments [line items]	
Possible change in risk variable, impact on pre-tax earnings	118.7
Operating Costs Decreases 5% | Southwest Saskatchewan	
Disclosure of nature and extent of risks arising from financial instruments [line items]	
Possible change in risk variable, impact on pre-tax earnings	$ 65.0

Goodwill (Details) - CAD ($) $ in Millions	12 Months Ended Dec. 31, 2022	 Dec. 31, 2021
Schedule of Goodwill [Roll Forward]		
Goodwill, beginning of year	$ 211.5	$ 223.3
Goodwill	(0.8)	(1.2)
Goodwill, end of year	203.9	211.5
Saskatchewan Viking Disposition		
Schedule of Goodwill [Roll Forward]		
Asset dispositions	0.0	(10.6)
Saskatchewan Viking asset disposition		
Schedule of Goodwill [Roll Forward]		
Asset dispositions	$ (6.8)	$ 0.0

Other Current Liabilities (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
Subclassifications of assets, liabilities and equities [abstract]		
Long-term compensation liability	$ 49.1	$ 40.6
Lease liability	24.9	25.5
Decommissioning liability	41.6	34.2
Other current liabilities	$ 115.6	$ 100.3

Long-term Debt (Reconciliation Long Term Debt) (Details) $ in Millions, $ in Millions	Dec. 31, 2022 CAD ($)	Dec. 31, 2022 USD ($)	Dec. 31, 2021 CAD ($)	Dec. 31, 2020 CAD ($)
Disclosure of detailed information about borrowings [line items]				
Long-term debt	$ 1,441.5		$ 1,970.2	$ 2,259.6
Long-term debt due within one year	538.7		278.1	
Long-term debt due beyond one year	902.8		1,692.1	
Bank debt				
Disclosure of detailed information about borrowings [line items]				
Bank debt	0.0		331.4	
Senior guaranteed notes				
Disclosure of detailed information about borrowings [line items]				
Senior guaranteed notes			$ 1,638.8	
Long-term debt due beyond one year	$ 195.0	$ 921.0		

Long-term Debt (Bank Debt) (Details)	Dec. 31, 2022 CAD ($) bank	Dec. 31, 2021 CAD ($)
Disclosure of detailed information about borrowings [line items]		
Credit facility, maximum borrowing capacity	$ 2,360,000,000	
Maximum ratio of senior debt to EBITDA	3.5	
Maximum ratio of total debt to EBITDA	4.0	
Maximum ratio of senior debt to adjusted capital	0.55	
Letter of credit amount outstanding	$ 1,800,000	$ 1,000,000
Syndicated Unsecured Credit Facility		
Disclosure of detailed information about borrowings [line items]		
Credit facility, maximum borrowing capacity	$ 2,260,000,000	
Number of banks | bank	11	
Unsecured Operating Credit Facility		
Disclosure of detailed information about borrowings [line items]		
Credit facility, maximum borrowing capacity	$ 100,000,000	
Number of banks | bank	1	

Long-term Debt (Senior Guaranteed Noted) (Details)	Dec. 31, 2022 CAD ($)	Dec. 31, 2022 USD ($)	Dec. 31, 2021 CAD ($)	Dec. 31, 2020 CAD ($)
Disclosure of detailed information about borrowings [line items]				
Long-term debt	$ 902,800,000		$ 1,692,100,000	
Current notes and debentures issued and current portion of non-current notes and debentures issued			278,100,000	
Non-current portion of non-current notes and debentures issued	902,800,000		1,360,700,000	
Borrowings	1,441,500,000		1,970,200,000	$ 2,259,600,000
Senior guaranteed notes				
Disclosure of detailed information about borrowings [line items]				
Principal due on maturity	1,249,800,000			
Senior guaranteed notes			1,638,800,000	
Principal Due On Maturity, Current	445,000,000.0			
Principal Due On Maturity, Non-current	804,800,000			
Senior guaranteed notes				
Disclosure of detailed information about borrowings [line items]				
Long-term debt	195,000,000	$ 921,000,000		
Senior guaranteed notes			1,638,800,000	
Senior guaranteed notes | Cross Currency Derivative Contract Swap 2018				
Disclosure of detailed information about borrowings [line items]				
Principal	1,050,000,000.00			
Borrowings		$ 921,000,000		
4.76% Interest, Maturing 5/22/2022				
Disclosure of detailed information about borrowings [line items]				
Principal	$ 0			
Borrowings, interest rate	4.76%	4.76%		
Principal due on maturity	$ 0			
Senior guaranteed notes	$ 0		25,000,000.0	
4.00% Interest, Maturing 5/22/2022				
Disclosure of detailed information about borrowings [line items]				
Principal		$ 0		
Borrowings, interest rate	4.00%	4.00%		
Principal due on maturity	$ 0			
Senior guaranteed notes	$ 0		253,100,000	

4.12% Interest, Maturing 4/11/2023			
Disclosure of detailed information about borrowings [line items]			
Principal		$ 61,500,000	
Borrowings, interest rate	4.12%	4.12%	
Principal due on maturity	$ 80,300,000		
Senior guaranteed notes	83,200,000		77,800,000
3.58% Interest, Maturing 4/11/2023			
Disclosure of detailed information about borrowings [line items]			
Principal	$ 80,000,000.0		
Borrowings, interest rate	3.58%	3.58%	
Principal due on maturity	$ 80,000,000.0		
Senior guaranteed notes	80,000,000.0		80,000,000.0
4.11% Interest, Maturing 6/12/2023			
Disclosure of detailed information about borrowings [line items]			
Principal	$ 10,000,000.0		
Borrowings, interest rate	4.11%	4.11%	
Principal due on maturity	$ 10,000,000.0		
Senior guaranteed notes	$ 10,000,000.0		10,000,000.0
3.78% Interest, Maturing 6/12/2023			
Disclosure of detailed information about borrowings [line items]			
Principal		$ 270,000,000.0	
Borrowings, interest rate	3.78%	3.78%	
Principal due on maturity	$ 274,700,000		
Senior guaranteed notes	365,500,000		341,700,000
3.85% Interest, Maturing 6/20/2024			
Disclosure of detailed information about borrowings [line items]			
Principal	$ 40,000,000.0		
Borrowings, interest rate	3.85%	3.85%	
Principal due on maturity	$ 40,000,000.0		
Senior guaranteed notes	$ 40,000,000.0		40,000,000.0
3.75% Interest, Maturing 6/20/2024			
Disclosure of detailed information about borrowings [line items]			
Principal		$ 257,500,000	
Borrowings, interest rate	3.75%	3.75%	
Principal due on maturity	$ 276,400,000		
Senior guaranteed notes	$ 348,500,000		325,900,000
4.30% Interest, Maturing 4/11/2025			

Disclosure of detailed information about borrowings [line items]			
Principal		$ 82,000,000.0	
Borrowings, interest rate	4.30%	4.30%	
Principal due on maturity	$ 107,000,000.0		
Senior guaranteed notes	111,000,000.0		103,800,000
3.94% Interest, Maturing 4/22/2025			
Disclosure of detailed information about borrowings [line items]			
Principal	$ 65,000,000.0		
Borrowings, interest rate	3.94%	3.94%	
Principal due on maturity	$ 65,000,000.0		
Senior guaranteed notes	$ 65,000,000.0		65,000,000.0
4.08% Interest, Maturing 4/22/2025			
Disclosure of detailed information about borrowings [line items]			
Principal		$ 230,000,000.0	
Borrowings, interest rate	4.08%	4.08%	
Principal due on maturity	$ 291,100,000		
Senior guaranteed notes	$ 311,300,000		291,100,000
4.18% Interest, Maturing 4/22/2027			
Disclosure of detailed information about borrowings [line items]			
Principal		$ 20,000,000.0	
Borrowings, interest rate	4.18%	4.18%	
Principal due on maturity	$ 25,300,000		
Senior guaranteed notes	$ 27,000,000.0		$ 25,400,000

Leases (Right-of-Use Assets) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of quantitative information about right-of-use assets [line items]		
Right-of-use asset at cost	$ 161.5	$ 158.5
Accumulated depreciation	(83.4)	(67.1)
Right-of-use asset	78.1	91.4
Right-Of-Use Assets, Net Carrying Amount Rollforward [Roll Forward]		
Net carrying amount, beginning of year	91.4	
Additions	3.9	
Depreciation	(16.6)	
Lease modification	(0.6)	
Net carrying amount, end of year	78.1	91.4
Sublease income	3.6	5.4
Other Income (Loss)		
Right-Of-Use Assets, Net Carrying Amount Rollforward [Roll Forward]		
Sublease income	3.6	5.4
Office		
Disclosure of quantitative information about right-of-use assets [line items]		
Right-of-use asset at cost	121.9	121.6
Accumulated depreciation	(55.4)	(44.3)
Right-of-use asset	66.5	77.3
Right-Of-Use Assets, Net Carrying Amount Rollforward [Roll Forward]		
Net carrying amount, beginning of year	77.3	
Additions	0.0	
Depreciation	(10.8)	
Lease modification	0.0	
Net carrying amount, end of year	66.5	77.3
Fleet Vehicles		
Disclosure of quantitative information about right-of-use assets [line items]		
Right-of-use asset at cost	28.5	25.2
Accumulated depreciation	(20.4)	(16.1)
Right-of-use asset	8.1	9.1
Right-Of-Use Assets, Net Carrying Amount Rollforward [Roll Forward]		
Net carrying amount, beginning of year	9.1	
Additions	3.2	
Depreciation	(4.2)	
Lease modification	0.0	
Net carrying amount, end of year	8.1	9.1
Other		
Disclosure of quantitative information about right-of-use assets [line items]		
Right-of-use asset at cost	11.1	11.7
Accumulated depreciation	(7.6)	(6.7)

Right-of-use asset	3.5	5.0
Right-Of-Use Assets, Net Carrying Amount Rollforward [Roll Forward]		
Net carrying amount, beginning of year	5.0	
Additions	0.7	
Depreciation	(1.6)	
Lease modification	(0.6)	
Net carrying amount, end of year	$ 3.5	$ 5.0

Leases (Lease Liability) (Details) - CAD ($) $ in Millions	12 Months Ended Dec. 31, 2022	Dec. 31, 2021
Lease Liability, Period Increase (Decrease) Rollforward [Roll Forward]		
Lease liability, beginning of year	$ 141.4	$ 156.5
Additions	3.8	5.9
Financing	5.7	6.5
Payments on lease liability	(26.1)	(27.7)
Other	(0.7)	0.2
Lease liability, end of year	124.1	141.4
Expected to be incurred within one year	24.9	25.5
Expected to be incurred beyond one year	99.2	115.9
Expense relating to variable lease payments not included in measurement of lease liabilities	1.5	1.5
Expense relating to short-term leases for which recognition exemption has been used	$ 0.8	$ 0.6

Leases (Undiscounted Lease Payments Maturity Schedule) (Details) $ in Millions	Dec. 31, 2022 CAD ($)
Disclosure of maturity analysis of finance lease payments receivable [line items]	
Undiscounted cash flows related to lease liability	$ 142.8
1 year	
Disclosure of maturity analysis of finance lease payments receivable [line items]	
Undiscounted cash flows related to lease liability	25.5
2 to 3 years	
Disclosure of maturity analysis of finance lease payments receivable [line items]	
Undiscounted cash flows related to lease liability	41.3
4 to 5 years	
Disclosure of maturity analysis of finance lease payments receivable [line items]	
Undiscounted cash flows related to lease liability	33.6
More than 5 years	
Disclosure of maturity analysis of finance lease payments receivable [line items]	
Undiscounted cash flows related to lease liability	$ 42.4

Other Long-term Liabilities (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
Subclassifications of assets, liabilities and equities [abstract]		
Long-term compensation liability	$ 40.8	$ 35.8

Decommissioning Liability (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Provisions for Changes in Decommissioning Liability [Roll Forward]		
Decommissioning liability, beginning of year	$ 918.8	
Decommissioning liability, end of year		$ 918.8
Expected to be incurred within one year	(41.6)	(34.2)
Decommissioning liability	633.9	884.6
Provision for decommissioning, restoration and rehabilitation costs		918.8
Decommissioning liability, undiscounted cash flows	$ 894.9	$ 896.6
Discount rate applied to cash flow projections	3.28%	1.68%
Inflation rate used to extrapolate cash flow projections	2.09%	1.82%
Decommissioning liability		
Provisions for Changes in Decommissioning Liability [Roll Forward]		
Decommissioning liability, beginning of year	$ 918.8	$ 1,022.7
Liabilities incurred	21.6	13.6
Liabilities acquired through capital acquisitions	3.4	30.0
Liabilities disposed through capital dispositions	(46.7)	(220.3)
Liabilities settled (1)	(43.1)	(48.9)
Revaluation of acquired decommissioning liabilities (2)	3.8	36.1
Change in estimates	(11.4)	74.2
Change in discount and inflation rate estimates	(163.0)	(3.8)
Accretion	19.2	15.4
Reclassified as liabilities associated with assets held for sale	(28.4)	0.0
Foreign exchange	1.3	(0.2)
Decommissioning liability, end of year	675.5	918.8
Expected to be incurred within one year	(41.6)	(34.2)
Decommissioning liability		884.6
Proceeds from government subsidy programs	23.0	28.7
Provision for decommissioning, restoration and rehabilitation costs	$ 675.5	$ 918.8

Shareholders' Capital (Details) - CAD ($) $ in Millions	12 Months Ended		
	Mar. 04, 2022	Dec. 31, 2022	Dec. 31, 2021
Amount			
Redemption of restricted shares		$ 2.6	$ 0.8
Common shares repurchased for cancellation		294.2	17.5
Shareholders’ capital		$ 16,419.3	$ 16,706.9
Percent of public float	10.00%		
Shareholders’ capital			
Number of shares			
Common shares, beginning of year (in shares)		579,484,032	530,035,922
Issued on capital acquisitions (in shares)		0	50,000,000
Issued on redemption of restricted stock (in shares)		1,713,730	2,109,241
Issued on exercise of stock options (in shares)		1,038,321	155,869
Common shares repurchased (in shares)	57,309,975	31,347,100	2,817,000
Common shares, end of year (in shares)		550,888,983	579,484,032
Amount			
Common shares, beginning of year		$ 16,963.4	$ 16,707.6
Issued on capital acquisitions		0.0	264.5
Redemption of restricted shares		5.2	8.5
Issued on exercise of stock options		1.4	0.3
Common shares repurchased for cancellation		(294.2)	(17.5)
Common shares, end of year		16,675.8	16,963.4
Cumulative share issue costs, net of tax		(256.5)	(256.5)
Shareholders’ capital		$ 16,419.3	$ 16,706.9

Deficit (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
Disclosure of reserves within equity [line items]		
Deficit	$ (10,563.3)	$ (11,848.7)
Accumulated earnings (deficit)		
Disclosure of reserves within equity [line items]		
Deficit	(2,700.6)	(4,184.0)
Accumulated gain on shares issued pursuant to DRIP and SDP		
Disclosure of reserves within equity [line items]		
Deficit	8.4	8.4
Accumulated tax effect on redemption of restricted shares		
Disclosure of reserves within equity [line items]		
Deficit	15.8	13.2
Accumulated dividends		
Disclosure of reserves within equity [line items]		
Deficit	$ (7,886.9)	$ (7,686.3)

Capital Management (Details) $ in Millions	Dec. 31, 2022 CAD ($)	Dec. 31, 2021 CAD ($)	Dec. 31, 2020 CAD ($)
Capital Management [Abstract]			
Long-term debt	$ 1,441.5	$ 1,970.2	$ 2,259.6
Adjusted working capital (surplus) deficiency	(95.1)	201.6	
Unrealized foreign exchange on translation of US dollar long-term debt	(191.7)	(166.8)	
Net debt	1,154.7	2,005.0	
Shareholders’ equity	6,493.4	5,405.3	$ 2,822.8
Total capitalization	$ 7,648.1	$ 7,410.3	
Net debt to adjusted cash flow from operations ratio	0.5	1.4	

Capital Management (Cash Flows to Adjusted Funds Flow from Operations) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Capital Management [Abstract]		
Cash flow from operating activities	$ 2,192.2	$ 1,495.8
Changes in non-cash working capital	15.0	(51.6)
Transaction costs	5.1	12.5
Decommissioning expenditures	20.1	20.2
Adjusted funds flow from operations	$ 2,232.4	$ 1,476.9

Commodity Derivative Losses (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure Of Maturity Analysis For Derivative And Non-derivative Financial Liabilities [Line Items]		
Unrealized gains (losses)	$ 171.0	$ (141.4)
Commodity derivative losses	(473.4)	(488.9)
Commodity contracts		
Disclosure Of Maturity Analysis For Derivative And Non-derivative Financial Liabilities [Line Items]		
Realized losses	(641.8)	(360.8)
Unrealized gains (losses)	168.4	(128.1)
Commodity derivative losses	$ (473.4)	$ (488.9)

Other Income (Loss) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Analysis of income and expense [abstract]		
Unrealized gain on long-term investments	$ 0.0	$ 3.1
Realized gain on sale of long-term investments	0.0	7.0
Gain on capital dispositions	25.9	58.4
Government grant for decommissioning expenditures	23.0	28.7
Sublease income	3.6	5.4
Other	6.3	(3.2)
Other income	$ 58.8	$ 99.4

Interest Expense (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Analysis of income and expense [abstract]		
Interest	$ 64.7	$ 88.9
Unrealized (gain) loss on interest derivative contracts	(1.1)	1.7
Interest expense	$ 63.6	$ 90.6

Foreign Exchange Gain (Loss) (Details) - CAD ($) $ in Millions	12 Months Ended Dec. 31, 2022	Dec. 31, 2021
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Foreign exchange gain (loss)	$ (18.8)	$ 4.4
CCS - Principal and foreign exchange swaps		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Realized gain (loss)	63.8	0.0
Translation of US dollar long-term debt		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Realized gain (loss)	(94.3)	37.0
Unrealized gain (loss) on CCS - principal and foreign exchange swaps		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Unrealized gain (loss)	4.4	(34.4)
Other		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Unrealized gain (loss)	$ 7.3	$ 1.8

Income Taxes (Provision for income taxes) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Current tax:		
Canada	$ 0.0	$ 0.0
United States	0.0	0.0
Current tax expense	0.0	0.0
Deferred tax expense (recovery):		
Canada	415.1	715.5
United States	(27.2)	84.2
Deferred	387.9	799.7
Income tax expense	$ 387.9	$ 799.7

Income Taxes (Income Tax Rate Reconciliation) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Income Taxes [Abstract]		
Net income before tax	$ 1,871.3	$ 3,163.8
Statutory income tax rate	24.82%	25.16%
Expected provision for income taxes	$ 464.5	$ 796.0
Change in corporate tax rates and tax rate variance	1.6	21.9
Tax rates in foreign jurisdictions	2.1	5.8
Restricted share bonus plan	0.6	(1.6)
Recognition of deferred tax assets	(83.2)	(70.7)
Derecognition of deferred tax assets	0.0	37.5
Non-taxable capital gains	(0.2)	(2.5)
Non-deductible disposition of goodwill	1.9	3.0
Other	0.6	10.3
Income tax expense	$ 387.9	$ 799.7

Income Taxes (Composition of Net Deferred Income Tax Asset) (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
Income Taxes [Abstract]		
Deferred income tax assets	$ 278.8	$ 570.1
Deferred income tax liabilities	(77.3)	0.0
Net deferred income tax asset	$ 201.5	$ 570.1

Income Taxes (Deferred Tax Assets and Liabilities, Net) (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021	Dec. 31, 2020
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]			
Net deferred income tax liabilities	$ (201.5)	$ (570.1)	$ (1,367.9)
To be settled within one year			
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]			
Net deferred income tax liabilities	(19.6)	(60.1)	
To be settled beyond one year			
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]			
Net deferred income tax liabilities	$ (181.9)	$ (510.0)	

Income Taxes (Deferred Tax Rollforward) (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	$ (201.5)	$ (570.1)
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	(19.3)	(1.9)
(Charged) / credited to earnings	(387.9)	(799.7)
Net deferred income tax liabilities at the end of the period	(570.1)	(1,367.9)
Deferred income tax assets:		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	(974.7)	(1,139.7)
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	(19.3)	(1.9)
(Charged) / credited to earnings	(184.3)	(266.6)
Net deferred income tax liabilities at the end of the period	(1,139.7)	(1,404.4)
Property, plant and equipment		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	0.0	0.0
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0
(Charged) / credited to earnings	0.0	(248.9)
Net deferred income tax liabilities at the end of the period	0.0	(248.9)
Decommissioning liability		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	(167.4)	(229.6)
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0
(Charged) / credited to earnings	(62.2)	(32.6)
Net deferred income tax liabilities at the end of the period	(229.6)	(262.2)
Income tax losses carried forward		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	(744.6)	(814.2)
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0
(Charged) / credited to earnings	(69.6)	(18.9)
Net deferred income tax liabilities at the end of the period	(814.2)	(833.1)
Risk management contracts		

Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	(2.1)	(41.1)
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0
(Charged) / credited to earnings	(39.0)	29.5
Net deferred income tax liabilities at the end of the period	(41.1)	(11.6)
Lease liabilities		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	(30.7)	(35.3)
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0
(Charged) / credited to earnings	(4.6)	(4.8)
Net deferred income tax liabilities at the end of the period	(35.3)	(40.1)
Other		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	(29.9)	(19.5)
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	(19.3)	(1.9)
(Charged) / credited to earnings	(8.9)	9.1
Net deferred income tax liabilities at the end of the period	(19.5)	(8.5)
Deferred income tax liabilities:		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	773.2	569.6
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0
(Charged) / credited to earnings	(203.6)	(533.1)
Net deferred income tax liabilities at the end of the period	569.6	36.5
Property, plant and equipment		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	743.1	533.4
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0
(Charged) / credited to earnings	(209.7)	(533.4)
Net deferred income tax liabilities at the end of the period	533.4	0.0
Risk management contracts		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	10.8	13.4
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0

(Charged) / credited to earnings	2.6	(3.5)
Net deferred income tax liabilities at the end of the period	13.4	9.9
ROU asset		
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]		
Net deferred income tax liabilities at the beginning of the period	19.3	22.8
Changes in deferred tax liability (asset) [abstract]		
(Charges) / credits due to acquisitions & other	0.0	0.0
(Charged) / credited to earnings	3.5	3.8
Net deferred income tax liabilities at the end of the period	$ 22.8	$ 26.6

Income Taxes (Tax Pools) (Details) - CAD ($) $ in Millions	12 Months Ended Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2015	Dec. 31, 2014
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]				
Tax pools	$ 9,868.0	$ 8,711.0		
Operating loss carryforward	1,990.0	1,360.0		
Operating loss carryforwards that will expire in the years 2026 through 2039	2,220.0	2,300.0		
Operating loss carryforwards that will expire in the years 2029 through 2037		1,550.0		
Operating loss carryforwards that will not expire		744.9		
Unrealized losses	861.0	507.2		
Other temporary differences	69.0	69.0		
Temporary differences associated with investments in subsidiaries, branches and associates and interests in joint arrangements for which deferred tax liabilities have not been recognised	1,720.0	1,480.0		
Tax pools of acquired entity disallowed				$ 149.3
Investment tax credit of acquired entity disallowed			$ 12.6	
Deferred income tax expense recognized from removing tax pools	37.5			
Canada				
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]				
Tax pools	7,012.5	5,685.8		
United States				
Disclosure of temporary difference, unused tax losses and unused tax credits [line items]				
Tax pools	$ 2,855.5	$ 3,025.2		

Share-based Compensation - Schedule of Shares Activitiy (Details)	12 Months Ended	
	Dec. 31, 2022 shares $ / shares	Dec. 31, 2021 shares $ / shares
Share-based Payment Arrangements [Roll Forward]		
Redeemed (in shares)	(1,586,890)	
Balance, end of year (in shares)	3,889,130,000	
Share Based Payment Arrangements, Weighted Average Exercise Price [Roll Forward]		
Exercised, Weighted average exercise price (in dollars per share) | $ / shares	$ 4.43	
Restricted Shares		
Share-based Payment Arrangements [Roll Forward]		
Balance, beginning of year (in shares)	3,267,717	4,704,129
Granted (in shares)	710,819	1,230,133
Redeemed (in shares)	(1,718,906)	(2,146,716)
Forfeited (in shares)	(14,892)	(519,829)
Balance, end of year (in shares)	2,244,738	3,267,717
Employee Share Value Plan		
Share-based Payment Arrangements [Roll Forward]		
Balance, beginning of year (in shares)	8,329,291	10,449,383
Granted (in shares)	1,288,598	2,570,746
Redeemed (in shares)	(3,691,820)	(3,417,496)
Forfeited (in shares)	(651,591)	(1,273,342)
Balance, end of year (in shares)	5,274,478	8,329,291
Performance Stock Units		
Share-based Payment Arrangements [Roll Forward]		
Balance, beginning of year (in shares)	3,214,620	3,789,689
Granted (in shares)	904,469	2,053,574
Redeemed (in shares)	(1,405,913)	(2,221,058)
Forfeited (in shares)	0	(407,585)
Balance, end of year (in shares)	2,713,176	3,214,620
Deferred Share Units		
Share-based Payment Arrangements [Roll Forward]		
Balance, beginning of year (in shares)	1,556,780	1,278,263
Granted (in shares)	208,693	278,517
Redeemed (in shares)	(19,594)	0
Forfeited (in shares)	0	0
Balance, end of year (in shares)	1,745,879	1,556,780
Stock Option Plan		
Share-based Payment Arrangements [Roll Forward]		
Balance, beginning of year (in shares)	5,839,464	
Redeemed (in shares)	(1,446,571)	
Forfeited (in shares)	(398,610)	

Expired (in shares)	(105,153)	
Balance, end of year (in shares)	3,889,130	5,839,464
Share Based Payment Arrangements, Weighted Average Exercise Price [Roll Forward]		
Beginning Balance, Weighted average exercise price (in dollars per share) | $ / shares	$ 4.04	
Exercised, Weighted average exercise price (in dollars per share) | $ / shares	3.16	
Forfeited, Weighted average exercise price (in dollars per share) | $ / shares	2.06	
Expired, Weighted average exercise price (in dollars per share) | $ / shares	9.22	
Ending Balance, Weighted average exercise price (in dollars per share) | $ / shares	$ 4.43	$ 4.04

Share-based Compensation - Schedule of Summarized Information on Options Outstanding (Details)	12 Months Ended Dec. 31, 2022 shares $ / shares	Dec. 31, 2021 shares
Disclosure of classes of share capital [line items]		
Weighted average exercise price per share for options outstanding (in dollars per share)	3,889,130,000	
Weighted average remaining term (in years)	3 years 7 months 9 days	
Exercised, Weighted average exercise price (in dollars per share) | $ / shares	$ 4.43	
Number of stock options exercisable (in shares)	1,586,890	
Weighted average exercise price per share for options exercisable (in dollars per share) | $ / shares	$ 7.65	
Stock Option Plan		
Disclosure of classes of share capital [line items]		
Weighted average exercise price per share for options outstanding (in dollars per share)	3,889,130	5,839,464
Exercised, Weighted average exercise price (in dollars per share) | $ / shares	$ 3.16	
Number of stock options exercisable (in shares)	1,446,571	
Stock Option Plan | 1.09 - 1.65		
Disclosure of classes of share capital [line items]		
Weighted average exercise price per share for options outstanding (in dollars per share)	1,884,156,000	
Weighted average remaining term (in years)	4 years 3 months	
Exercised, Weighted average exercise price (in dollars per share) | $ / shares	$ 1.09	
Number of stock options exercisable (in shares)	307,638	
Weighted average exercise price per share for options exercisable (in dollars per share) | $ / shares	$ 1.09	
Stock Option Plan | 1.66 - 5.16		
Disclosure of classes of share capital [line items]		
Weighted average exercise price per share for options outstanding (in dollars per share)	470,946,000	
Weighted average remaining term (in years)	3 years 3 months 3 days	
Exercised, Weighted average exercise price (in dollars per share) | $ / shares	$ 3.92	
Number of stock options exercisable (in shares)	137,543	
Weighted average exercise price per share for options exercisable (in dollars per share) | $ / shares	$ 3.92	
Stock Option Plan | 5.17 - 9.86		
Disclosure of classes of share capital [line items]		
Weighted average exercise price per share for options outstanding (in dollars per share)	505,809,000	
Weighted average remaining term (in years)	4 years 9 months 7 days	
Exercised, Weighted average exercise price (in dollars per share) | $ / shares	$ 5.91	

Number of stock options exercisable (in shares)	113,490
Weighted average exercise price per share for options exercisable (in dollars per share) | $ / shares	$ 8.16
Stock Option Plan | 9.87 - 10.06	
Disclosure of classes of share capital [line items]	
Weighted average exercise price per share for options outstanding (in dollars per share)	1,028,219,000
Weighted average remaining term (in years)	2 years 7 days
Exercised, Weighted average exercise price (in dollars per share) | $ / shares	$ 10.06
Number of stock options exercisable (in shares)	1,028,219
Weighted average exercise price per share for options exercisable (in dollars per share) | $ / shares	$ 10.06

Share-based Compensation - Stock Options Outstanding (Details) shares in Thousands	12 Months Ended Dec. 31, 2022 shares $ / shares
Share-based Payment Arrangements [Abstract]	
Stock Options Balance, beginning of year (in shares) | shares	5,940,871
Stock Options Granted (in shares) | shares	534,264
Stock Options Exercised (in shares) | shares	(261,486)
Stock Options Forfeited (in shares) | shares	(285,047)
Stock Options Expired (in shares) | shares	(89,138)
Stock Options Balance, end of year (in shares) | shares	5,839,464
Weighted average exercise price Balance, beginning of year (in dollars per share) | $ / shares	$ 3.92
Weighted average exercise price Granted (in dollars per share) | $ / shares	5.23
Weighted average exercise price Exercised (in dollars per share) | $ / shares	2.23
Weighted average exercise price Forfeited (in dollars per share) | $ / shares	3.46
Weighted average exercise price Expired (in dollars per share) | $ / shares	10.06
Weighted average exercise price Balance, end of year (in dollars per share) | $ / shares	$ 4.04

Share-based Compensation - Narrative (Details) - CAD ($) $ / shares in Units, $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of classes of share capital [line items]		
Volume weighted average trading price (in dollars per share)	$ 4.04	$ 3.92
Share-based compensation	$ 77.3	$ 77.7
Share-based compensation expense capitalized	14.7	14.3
Current portion of long-term compensation liability	49.1	40.6
Long-term compensation liability	$ 40.8	$ 35.8
Weighted average share price	$ 9.52	$ 5.14

Per Share Amounts (Details) - shares	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Earnings per share [abstract]		
Weighted average shares – basic (in shares)	566,710,644	569,203,428
Dilutive impact of restricted shares (in shares)	4,357,422	5,895,220
Weighted average shares – diluted (in shares)	571,068,066	575,098,648

Financial Instruments and Derivatives - Carrying Amount and Fair Value of Financial Instruments (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial assets, carrying value	$ 235.3	$ 220.5
Financial assets, at fair value	235.3	220.5
Financial liabilities, carrying value	1,450.2	1,803.7
Financial liabilities, at fair value	1,381.6	1,783.3
Quoted prices in active markets for identical assets (Level 1)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial assets, at fair value	0.0	0.0
Financial liabilities, at fair value	0.0	0.0
Significant other observable inputs (Level 2)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial assets, at fair value	235.3	220.5
Financial liabilities, at fair value	1,381.6	1,783.3
Significant unobservable inputs (Level 3)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial assets, at fair value	0.0	0.0
Financial liabilities, at fair value	0.0	0.0
Derivatives		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial liabilities, carrying value	8.7	164.9
Financial liabilities, at fair value	8.7	164.9
Derivatives | Quoted prices in active markets for identical assets (Level 1)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial liabilities, at fair value	0.0	0.0
Derivatives | Significant other observable inputs (Level 2)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial liabilities, at fair value	8.7	164.9
Derivatives | Significant unobservable inputs (Level 3)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial liabilities, at fair value	0.0	0.0
Senior guaranteed notes		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial liabilities, carrying value	1,441.5	1,638.8
Financial liabilities, at fair value	1,372.9	1,618.4
Senior guaranteed notes | Quoted prices in active markets for identical assets (Level 1)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial liabilities, at fair value	0.0	0.0

Senior guaranteed notes | Significant other observable inputs (Level 2)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial liabilities, at fair value	1,372.9	1,618.4
Senior guaranteed notes | Significant unobservable inputs (Level 3)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial liabilities, at fair value	0.0	0.0
Derivatives		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial assets, carrying value	235.3	220.5
Financial assets, at fair value	235.3	220.5
Derivatives | Quoted prices in active markets for identical assets (Level 1)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial assets, at fair value	0.0	0.0
Derivatives | Significant other observable inputs (Level 2)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial assets, at fair value	235.3	220.5
Derivatives | Significant unobservable inputs (Level 3)		
Disclosure Of Fair Value Measurement Of Assets And Liabilities [Line Items]		
Financial assets, at fair value	$ 0.0	$ 0.0

Financial Instruments and Derivatives - Derivatives Assets and Liabilities (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Derivative Assets and Liabilities, At Fair Value [Roll Forward]		
Derivative assets (liabilities), beginning of year	$ 55.6	$ 197.0
Unrealized change in fair value	171.0	(141.4)
Derivative assets, end of year	226.6	55.6
Derivative assets, end of year	235.3	220.5
Derivative liabilities, end of year	(8.7)	(164.9)
Commodity contracts		
Derivative Assets and Liabilities, At Fair Value [Roll Forward]		
Derivative assets (liabilities), beginning of year	(154.4)	(26.3)
Unrealized change in fair value	168.4	(128.1)
Derivative assets, end of year	14.0	(154.4)
Derivative assets, end of year	22.6	5.4
Derivative liabilities, end of year	(8.6)	(159.8)
Interest rate swap contract		
Derivative Assets and Liabilities, At Fair Value [Roll Forward]		
Derivative assets (liabilities), beginning of year	5.6	7.3
Unrealized change in fair value	1.1	(1.7)
Derivative assets, end of year	6.7	5.6
Derivative assets, end of year	6.7	5.7
Derivative liabilities, end of year	0.0	(0.1)
Foreign exchange		
Derivative Assets and Liabilities, At Fair Value [Roll Forward]		
Derivative assets (liabilities), beginning of year	170.6	205.0
Unrealized change in fair value	4.4	(34.4)
Derivative assets, end of year	175.0	170.6
Derivative assets, end of year	175.1	175.6
Derivative liabilities, end of year	(0.1)	(5.0)
Equity Contracts		
Derivative Assets and Liabilities, At Fair Value [Roll Forward]		
Derivative assets (liabilities), beginning of year	33.8	11.0
Unrealized change in fair value	(2.9)	22.8
Derivative assets, end of year	30.9	33.8
Derivative assets, end of year	30.9	33.8
Derivative liabilities, end of year	$ 0.0	$ 0.0

Financial Instruments and Derivatives - Offsetting (Details) - Derivatives - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021
Offsetting Financial Assets		
Gross amount	$ 246.3	$ 218.9
Amount offset	11.0	1.6
Net amount	235.3	220.5
Offsetting Financial Liabilities		
Gross amount	(19.7)	(163.3)
Amount offset	(11.0)	(1.6)
Net amount	(8.7)	(164.9)
Gross amount assets (liabilities)	226.6	55.6
Net amount assets (liabilities)	$ 226.6	$ 55.6

Financial Instruments and Derivatives - Commodity Price Risk (Details) - Commodity price risk - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible change in risk variable percent	10.00%	10.00%
Commodity Price, Crude Oil		
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible increase in risk variable, impact on pre-tax earnings	$ (40.3)	$ (148.5)
Possible decrease in risk variable, impact on pre-tax earnings	38.8	141.2
Commodity Price, Natural Gas		
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible increase in risk variable, impact on pre-tax earnings	(3.1)	(1.1)
Possible decrease in risk variable, impact on pre-tax earnings	3.2	1.1
Differential, Natural Gas		
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible increase in risk variable, impact on pre-tax earnings	2.6	1.9
Possible decrease in risk variable, impact on pre-tax earnings	$ (2.6)	$ (1.9)

Financial Instruments and Derivatives - Foreign Exchange Risk (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Currency risk | US dollar long-term debt		
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible increase in risk variable, impact on pre-tax earnings	$ 124.6	$ 162.8
Possible decrease in risk variable, impact on pre-tax earnings	(124.6)	(162.8)
Currency risk | Currency swap contract		
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible increase in risk variable, impact on pre-tax earnings	(123.7)	(168.2)
Possible decrease in risk variable, impact on pre-tax earnings	123.7	168.2
Currency risk | Foreign exchange		
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible increase in risk variable, impact on pre-tax earnings	4.3	(0.9)
Possible decrease in risk variable, impact on pre-tax earnings	$ (4.3)	$ 0.9
Foreign exchange		
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible change in risk variable percent	10.00%	10.00%

Financial Instruments and Derivatives - Equity Contract Risk (Details) - Equity price risk - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible change in risk variable percent	50.00%	50.00%
Equity Contracts		
Disclosure of nature and extent of risks arising from financial instruments [line items]		
Possible increase in risk variable, impact on pre-tax earnings	$ 26.8	$ 27.4
Possible decrease in risk variable, impact on pre-tax earnings	$ (26.8)	$ (27.4)

Financial Instruments and Derivatives - Credit Risk (Details)	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of credit risk exposure [line items]		
Expected credit loss, percent	0.93%	0.92%
Credit risk | Investment grade		
Disclosure of credit risk exposure [line items]		
Concentration percentage	98.00%	
Credit risk | More than 90 days | Trade receivables		
Disclosure of credit risk exposure [line items]		
Concentration percentage	4.00%	3.00%

Financial Instruments and Derivatives - Liquidity Risk (Details) - CAD ($) $ in Millions	Dec. 31, 2022	Dec. 31, 2021	Dec. 31, 2020
Disclosure Of Maturity Analysis For Derivative And Non-derivative Financial Liabilities [Line Items]			
Cash	$ 289.9	$ 13.5	$ 8.8
Liquidity risk			
Disclosure Of Maturity Analysis For Derivative And Non-derivative Financial Liabilities [Line Items]			
Undrawn borrowing facilities	2,360.0		
Accounts payable and accrued liabilities	448.2	450.7	
Dividends payable	99.4	43.5	
Derivative liabilities	12.6	250.4	
Senior guaranteed notes	1,329.7	1,610.0	
Bank credit facilities		381.5	
Liquidity risk | 1 year			
Disclosure Of Maturity Analysis For Derivative And Non-derivative Financial Liabilities [Line Items]			
Accounts payable and accrued liabilities	448.2	450.7	
Dividends payable	99.4	43.5	
Derivative liabilities	12.6	249.0	
Senior guaranteed notes	486.6	280.3	
Bank credit facilities		11.7	
Liquidity risk | 2 to 3 years			
Disclosure Of Maturity Analysis For Derivative And Non-derivative Financial Liabilities [Line Items]			
Accounts payable and accrued liabilities	0.0	0.0	
Dividends payable	0.0	0.0	
Derivative liabilities	0.0	1.1	
Senior guaranteed notes	816.2	829.2	
Bank credit facilities		23.5	
Liquidity risk | 4 to 5 years			
Disclosure Of Maturity Analysis For Derivative And Non-derivative Financial Liabilities [Line Items]			
Accounts payable and accrued liabilities	0.0	0.0	
Dividends payable	0.0	0.0	
Derivative liabilities	0.0	0.3	
Senior guaranteed notes	26.9	474.6	
Bank credit facilities		346.3	
Liquidity risk | More than 5 years			
Disclosure Of Maturity Analysis For Derivative And Non-derivative Financial Liabilities [Line Items]			
Accounts payable and accrued liabilities	0.0	0.0	

Dividends payable	0.0	0.0
Derivative liabilities	0.0	0.0
Senior guaranteed notes	$ 0.0	25.9
Bank credit facilities		$ 0.0

Financial Instruments and Derivatives - Financial Derivatives (Details) $ in Millions, $ in Millions	Dec. 31, 2022 CAD ($) GJ / d $ / bbl $ / GJ MMBTU / d shares $ / MMBTU bbl / d	Dec. 31, 2022 USD ($) GJ / d $ / bbl $ / GJ MMBTU / d shares $ / MMBTU bbl / d	Dec. 31, 2021 shares
Disclosure of detailed information about financial instruments [line items]			
Number of shares | shares	5,839,464,000	5,839,464,000	5,940,871,000
Financial WTI Crude Oil Derivative Contracts – Canadian Dollar 2023 | Forward contract			
Disclosure of detailed information about financial instruments [line items]			
Nominal amount of hedging instrument | bbl / d	1,356	1,356	
Average swap price | $ / bbl	90.04	90.04	
Financial WTI Crude Oil Derivative Contracts – Canadian Dollar 2023 | Forward contract | Collar, Sold Call Price			
Disclosure of detailed information about financial instruments [line items]			
Nominal amount of hedging instrument | bbl / d	10,586	10,586	
Average swap price | $ / bbl	114.99	114.99	
Financial WTI Crude Oil Derivative Contracts – Canadian Dollar 2023 | Forward contract | Collar, Bought Put Price			
Disclosure of detailed information about financial instruments [line items]			
Average swap price | $ / bbl	101.39	101.39	
Financial WTI Crude Oil Derivative Contracts – Canadian Dollar 2023 | Sold Call Price | Forward contract			
Disclosure of detailed information about financial instruments [line items]			
Nominal amount of hedging instrument | bbl / d	616	616	
Average swap price | $ / bbl	118.11	118.11	
Financial WTI Crude Oil Derivative Contracts – Canadian Dollar 2023 | Bought Put Price | Forward contract			
Disclosure of detailed information about financial instruments [line items]			
Average swap price | $ / bbl	96.00	96.00	
Financial WTI Crude Oil Derivative Contracts – Canadian Dollar 2023 | Sold Put Price | Forward contract			
Disclosure of detailed information about financial instruments [line items]			
Average swap price | $ / bbl	76.00	76.00	

AECO Natural Gas Derivative Contracts – Canadian Dollar 2023 | Forward contract		
Disclosure of detailed information about financial instruments [line items]		
Nominal amount of hedging instrument | GJ / d	21,605	21,605
Average swap price | $ / GJ	4.68	4.68
AECO Natural Gas Derivative Contracts – Canadian Dollar 2023 | Sold Call Price | Forward contract		
Disclosure of detailed information about financial instruments [line items]		
Nominal amount of hedging instrument | GJ / d	7,397	7,397
Average swap price | $ / GJ	10.21	10.21
AECO Natural Gas Derivative Contracts – Canadian Dollar 2023 | Bought Put Price | Forward contract		
Disclosure of detailed information about financial instruments [line items]		
Average swap price | $ / GJ	4.48	4.48
AECO Natural Gas Derivative Contracts – Canadian Dollar 2024 January - March | Forward contract		
Disclosure of detailed information about financial instruments [line items]		
Nominal amount of hedging instrument | GJ / d	10,000	10,000
Average swap price | $ / GJ	5.13	5.13
AECO Natural Gas Derivative Contracts – Canadian Dollar 2024 January - March | Sold Call Price | Forward contract		
Disclosure of detailed information about financial instruments [line items]		
Nominal amount of hedging instrument | GJ / d	0	0
Average swap price | $ / GJ	0	0
AECO Natural Gas Derivative Contracts – Canadian Dollar 2024 January - March | Bought Put Price | Forward contract		
Disclosure of detailed information about financial instruments [line items]		
Average swap price | $ / GJ	0	0
WTI Crude Oil Differential Derivative Contracts – Canadian Dollar | January 2023 - March 2025		
Disclosure of detailed information about financial instruments [line items]		
Nominal amount of hedging instrument | MMBTU / d	17,500	17,500
Average swap price | $ / MMBTU	(0.94)	(0.94)
January 2023 - April 2023 | Receive		
Disclosure of detailed information about financial instruments [line items]		
Notional amount		$ 61.5
Fixed annual rate	412.00%	412.00%
January 2023 - April 2023 | Pay		

Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 80.3	
Fixed annual rate	371.00%	371.00%
January 2023 - June 2023 | Receive		
Disclosure of detailed information about financial instruments [line items]		
Notional amount		$ 270.0
Fixed annual rate	378.00%	378.00%
January 2023 - June 2023 | Pay		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 274.7	
Fixed annual rate	432.00%	432.00%
January 2023 - June 2024 | Receive		
Disclosure of detailed information about financial instruments [line items]		
Notional amount		$ 257.5
Fixed annual rate	375.00%	375.00%
January 2023 - June 2024 | Pay		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 276.4	
Fixed annual rate	403.00%	403.00%
January 2023 - April 2025 | Receive		
Disclosure of detailed information about financial instruments [line items]		
Notional amount		$ 82.0
Fixed annual rate	430.00%	430.00%
January 2023 - April 2025 | Pay		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 107.0	
Fixed annual rate	398.00%	398.00%
January 2023 - April 2025 | Receive		
Disclosure of detailed information about financial instruments [line items]		
Notional amount		$ 230.0
Fixed annual rate	408.00%	408.00%
January 2023 - April 2025 | Pay		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 291.1	
Fixed annual rate	413.00%	413.00%
January 2023 - April 2027 | Receive		

Disclosure of detailed information about financial instruments [line items]		
Notional amount		$ 20.0
Fixed annual rate	418.00%	418.00%
January 2023 - April 2027 | Pay		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 25.3	
Fixed annual rate	427.00%	427.00%
January 2023 | Receive		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 63.9	$ 15.0
January 2023 | Pay		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	20.5	$ 47.0
January 2023 - April 2023		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 11.9	
Number of shares | shares	4,060,760	4,060,760
January 2023 - April 2024		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 7.2	
Number of shares | shares	1,103,860	1,103,860
January 2023 - April 2025		
Disclosure of detailed information about financial instruments [line items]		
Notional amount	$ 3.6	
Number of shares | shares	386,014	386,014

Related Party Transactions (Details) - Key management personnel of entity or parent - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of transactions between related parties [line items]		
Key management personnel compensation, short-term benefits	$ 6.1	$ 6.1
Key management personnel compensation	0.0	2.8
Key management personnel compensation, share-based	24.2	23.4
Key management personnel compensation, termination benefits	$ 0.0	$ 1.8

Commitments (Details) $ in Millions	12 Months Ended Dec. 31, 2022 CAD ($)
Disclosure of maturity analysis of operating lease payments [line items]	
Operating	$ 49.1
Gas processing	550.3
Transportation	199.7
Capital	7.3
Total contractual commitments	806.4
Sublease income	18.1
1 year	
Disclosure of maturity analysis of operating lease payments [line items]	
Operating	11.7
Gas processing	64.6
Transportation	43.3
Capital	7.3
Total contractual commitments	126.9
2 to 3 years	
Disclosure of maturity analysis of operating lease payments [line items]	
Operating	15.7
Gas processing	105.4
Transportation	74.8
Capital	0.0
Total contractual commitments	195.9
4 to 5 years	
Disclosure of maturity analysis of operating lease payments [line items]	
Operating	9.8
Gas processing	88.5
Transportation	41.5
Capital	0.0
Total contractual commitments	139.8
More than 5 years	
Disclosure of maturity analysis of operating lease payments [line items]	
Operating	11.9
Gas processing	291.8
Transportation	40.1
Capital	0.0
Total contractual commitments	$ 343.8

Significant Subsidiaries (Details)	12 Months Ended Dec. 31, 2022
Disclosure of subsidiaries [line items]	
Proportion of ownership interest in subsidiary	100.00%
Crescent Point Resources Partnership	
Disclosure of subsidiaries [line items]	
Name of subsidiary	Crescent Point Resources Partnership
Country of incorporation of subsidiary	Canada
Crescent Point Holdings Ltd.	
Disclosure of subsidiaries [line items]	
Name of subsidiary	Crescent Point Holdings Ltd.
Country of incorporation of subsidiary	Canada
Crescent Point Energy U.S. Corp.	
Disclosure of subsidiaries [line items]	
Name of subsidiary	Crescent Point Energy U.S. Corp.
Country of incorporation of subsidiary	United States of America
Crescent Point U.S. Holdings Corp.	
Disclosure of subsidiaries [line items]	
Name of subsidiary	Crescent Point U.S. Holdings Corp.
Country of incorporation of subsidiary	United States of America

Supplemental Disclosures - Comprehensive Income Statement Presentation (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of analysis of other comprehensive income by item [line items]		
Total compensation expense	$ 158.1	$ 178.6
Operating		
Disclosure of analysis of other comprehensive income by item [line items]		
Total compensation expense	61.1	59.7
General and administrative		
Disclosure of analysis of other comprehensive income by item [line items]		
Total compensation expense	60.8	65.2
Share-based compensation		
Disclosure of analysis of other comprehensive income by item [line items]		
Total compensation expense	$ 36.2	$ 53.7

Supplemental Disclosures - Cash Flow Statement Presentation (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Operating activities		
Accounts receivable	$ (11.3)	$ (111.8)
Prepaids and deposits	(13.9)	15.3
Accounts payable and accrued liabilities	(3.5)	99.0
Other current liabilities	8.6	30.6
Other long-term liabilities	5.1	18.5
Changes in non-cash working capital:	(15.0)	51.6
Investing activities		
Accounts receivable	0.2	(2.1)
Other long-term receivable	0.0	9.3
Accounts payable and accrued liabilities	(7.6)	41.8
Changes in non-cash working capital:	(7.4)	49.0
Financing activities		
Prepaids and deposits	(44.2)	0.0
Accounts payable and accrued liabilities	4.0	0.0
Dividends declared	55.9	42.2
Change in non-cash working capital	$ 15.7	$ 42.2

Supplemental Disclosures - Cash Flow Supplemental Information (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Dividends Payable [Roll Forward]		
Dividends payable at the beginning of the period	$ 43.5	$ 1.3
Dividends paid	(144.7)	(5.6)
Dividends declared	200.6	47.8
Dividends payable at the end of the period	99.4	43.5
Long-term Debt [Roll Forward]		
Long-term debt beginning of the period	1,970.2	2,259.6
Decrease in bank debt, net	(338.5)	(34.6)
Repayment of senior guaranteed notes	(281.8)	(217.6)
Realized gain on cross currency swap maturity	63.8	
Foreign exchange	27.8	(37.2)
Long-term debt end of the period	1,441.5	1,970.2
Lease Liability [Roll Forward]		
Lease liability, beginning of year	141.4	156.5
Payments of lease liabilities	(20.4)	(21.2)
Additions	3.8	5.9
Other	(0.7)	0.2
Lease liability, end of year	$ 124.1	$ 141.4

Geographical Disclosure (Details) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	$ 3,993.0	$ 2,829.4
Non-current assets	8,497.2	8,760.3
Canada		
Disclosure of geographical areas [line items]		
Non-current assets	6,977.9	7,551.0
U.S.		
Disclosure of geographical areas [line items]		
Non-current assets	1,519.3	1,209.3
Oil and gas sales		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	4,493.1	3,206.5
Oil and gas sales | Canada		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	3,847.0	2,735.3
Oil and gas sales | U.S.		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	646.1	471.2
Crude oil sales | Canada		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	3,319.1	2,361.8
Crude oil sales | U.S.		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	553.3	381.9
NGL sales | Canada		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	224.8	213.5
NGL sales | U.S.		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	55.2	61.0
Natural gas sales | Canada		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	303.1	160.0
Natural gas sales | U.S.		
Disclosure of geographical areas [line items]		
Revenue from contracts with customers	$ 37.6	$ 28.3

Subsequent Events (Details) - Kaybob Duvernay - CAD ($) $ in Millions	Jan. 11, 2023	Aug. 31, 2022
Disclosure of non-adjusting events after reporting period [line items]		
Consideration, net		$ 87.0
Major business combination		
Disclosure of non-adjusting events after reporting period [line items]		
Consideration, net	$ 370.6	
Deposit on acquisition	$ 18.7	